SOUTHERN CALIFORNIA EDISON®

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2025 GRC
A.23-05-010

Workpapers

SCE-04 Vol.05 Part 3
Wildfire Management - Emergent Technology and Inspections and Remediations

May 2023

2025 General Rate Case
Index of Workpapers
SCE-04 Vol. 05 Part 3 – Wildfire Management – Emergent Technology and Inspections and Remediations

Workpaper Title:

O&M Detail for Distribution Fault Anticipation

WP SCE-04 Vol. 05 Part 3

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2025 General Rate Case

A. 23-05-

Workpapers

SCE-04 Resiliency
Volume 5 Pt. 3 - Wildfire Management
Distribution Fault Anticipation

May 2023

2025 GRC Summary

(Constant 2022 $000)

Beginning of Workpapers for:

Exhibit:	SCE-04 Resiliency
Volume:	5 Pt. 3 - Wildfire Management
Business Planning Element:	Wildfire Management
Activity:	Distribution Fault Anticipation
Witness:	Ray Fugere

Cost Type	Recorded/Adj. 2022	Forecast 2025
Labor	42	0
Non-Labor	471	0
Other	0	0
Total	**513**	**0**

Due to rounding, totals may not tie to individual items.

Description of Activity:
This activity includes the costs associated with rollout of Distribution Fault Anticipation devices as well as data services and analysis provided by Texas A&M.

Forecast Methods - Summary of Results of Methods Studied

(Constant 2022 $000)

Exhibit:	SCE-04 Resiliency
Volume:	5 Pt. 3 - Wildfire Management
Business Planning Element:	Wildfire Management
Activity:	Distribution Fault Anticipation
Witness:	Ray Fugere

Cost Type	Recorded/Adj.				
	2018	2019	2020	2021	2022
Labor	0	0	0	10	42
Non-Labor	0	197	277	145	471
Other	0	0	0	0	0
Total	**0**	**197**	**277**	**155**	**513**

Cost Type	Results of Linear Trending					
	3 Years: 2020 - 2022		4 Years: 2019 - 2022		5 Years: 2018 - 2022	
	$	r2*	$	r2*	$	r2*
Labor	101	0.92	74	0.78	57	0.67
Non-Labor	687	0.35	583	0.39	663	0.66
Other	0	0.00	0	0.00	0	0.00
Total	**787**	**N/A**	**657**	**N/A**	**720**	**N/A**

Cost Type	Results of Averaging							
	2 Years:		3 Years:		4 Years:		5 Years:	
	2021 - 2022	sd**	2020 - 2022	sd**	2019 - 2022	sd**	2018 - 2022	sd**
Labor	26	16	17	18	13	17	10	16
Non-Labor	308	163	298	134	272	124	218	155
Other	0	0	0	0	0	0	0	0
Total	**334**	**N/A**	**315**	**N/A**	**285**	**N/A**	**228**	**N/A**

Cost Type	Last Recorded Year		
	2023	2024	2025
Labor	42	42	42
Non-Labor	471	471	471
Other	0	0	0
Total	**513**	**513**	**513**

Cost Type	Itemized Forecast		
	2023	2024	2025
Labor	0	0	0
Non-Labor	350	351	0
Other	0	0	0
Total	**350**	**351**	**0**

** r2 = R Squared (Based on recorded years data)*

*** sd = standard deviation (Based on recorded years data)*

2025 GRC Selected Forecast Method

(Constant 2022 $000)

Exhibit:	SCE-04 Resiliency
Volume:	5 Pt. 3 - Wildfire Management
Business Planning Element:	Wildfire Management
Activity:	Distribution Fault Anticipation
Witness:	Ray Fugere

Cost Type	Recorded/Adj.					Forecast			Selected Forecast		TY Forecast Incr/(Decr) from 2022
	2018	2019	2020	2021	2022	2023	2024	2025	Method	($000)	
Labor		0		10	42				Itemized		
Non-Labor		197	277	145	471	350	351		Itemized		
Other											
Total	**0**	**197**	**277**	**155**	**513**	**350**	**351**	**0**		**0**	**0**

Due to rounding, totals may not tie to individual items.

Analysis of Forecasting Methods

Itemized Forecast:
Itemized Forecast Method

Other Forecast Methods not Selected

Last Recorded Year:
In D.89-12-057, and subsequently in D.04-07-022, the CPUC stated that if recorded expenses have been relatively stable for three or more years, the last recorded year is an appropriate base estimate. For this activity the Last Recorded Year method does not account for the variables discussed in testimony to determine the 2025 Test Year forecast. Therefore, the Last Recorded Year method is not appropriate.

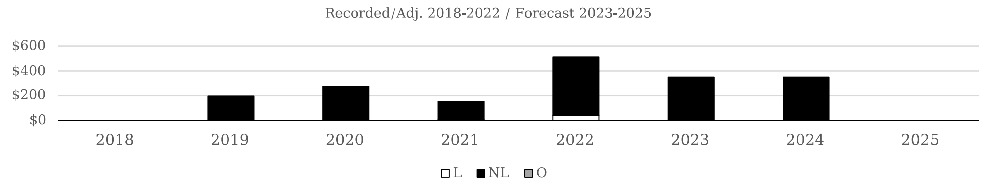
Linear Trending:
In D.89-12-057, and subsequently in D.04-07-022, the CPUC stated that if recorded expenses have been relatively stable for three or more years, the last recorded year is an appropriate base estimate. For this activity the Linear Trending method does not account for the variables discussed in testimony to determine the 2025 Test Year forecast. Therefore, the Linear Trending method is not appropriate.

Averaging:
In D.89-12-057, and subsequently in D.04-07-022, the CPUC stated that if recorded expenses have significant fluctuations from year to year, or expenses are influenced by external forces beyond the utility’s control, an average of recorded-expenses is appropriate. For this activity the Averaging method does not account for the variables discussed in testimony to determine the 2025 Test Year forecast. Therefore, the Averaging method is not appropriate.

2025 GRC Year Over Year Variance

(Constant 2022 $000)

Exhibit:	SCE-04 Resiliency
Volume:	5 Pt. 3 - Wildfire Management
Business Planning Element:	Wildfire Management
Activity:	Distribution Fault Anticipation
Witness:	Ray Fugere



Cost Type		Recorded/Adj. 2018	2019	2020	2021	2022	Forecast 2023	2024	2025
Recorded / Forecast	Labor	0	0	0	10	42	0	0	0
	Non-Labor	0	197	277	145	471	350	351	0
	Other	0	0	0	0	0	0	0	0
	Total	**0**	**197**	**277**	**155**	**513**	**350**	**351**	**0**

		2019	2020	2021	2022	2023	2024	2025
Labor	Prior Year Total	0	0	0	10	42	0	0
	Change	0	0	10	32	(42)	0	0
	Total	**0**	**0**	**10**	**42**	**0**	**0**	**0**
Non-Labor	Prior Year Total	0	197	277	145	471	350	351
	Change	197	79	(132)	326	(121)	1	(351)
	Total	**197**	**277**	**145**	**471**	**350**	**351**	**0**
Other	Prior Year Total	0	0	0	0	0	0	0
	Change	0	0	0	0	0	0	0
	Total	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Total Change	Prior Year Total	0	197	277	155	513	350	351
	Change	197	79	(122)	358	(163)	1	(351)
	Total	**197**	**277**	**155**	**513**	**350**	**351**	**0**

Due to rounding, totals may not tie to individual items.

2025 GRC Forecast Commentary

(Constant 2022 $000)

Exhibit:	SCE-04 Resiliency
Volume:	5 Pt. 3 - Wildfire Management
Business Planning Element:	Wildfire Management
Activity:	Distribution Fault Anticipation
Witness:	Ray Fugere

Summary of Changes: See Testimony

Cost Type		Recorded/Adj.					Forecast		
		2018	2019	2020	2021	2022	2023	2024	2025
Recorded / Forecast	Labor	0	0	0	10	42	0	0	0
	Non-Labor	0	197	277	145	471	350	351	0
	Other	0	0	0	0	0	0	0	0
	Total	**0**	**197**	**277**	**155**	**513**	**350**	**351**	**0**

Due to rounding, totals may not tie to individual items.

Recorded (2018-2022)

See Testimony

Forecast (2023-2025)

See Testimony

Workpaper Title:

Remote Grid - Resilient by Design Preventing Wildfires and Blackouts

WP SCE-04 Vol. 05 Part 3

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Resilient by design: Preventing wildfires and blackouts with microgrids

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HIGHLIGHTS

- A novel strategy for managing wildfires and blackouts using microgrids is proposed.
- The Fire Weather Index is used to describe the fire risk distribution in a grid.
- The Grid and Wildfire Index are linked by line locations and fire risk distribution.
- Set Victoria Australia as a case study, 68% of the overall system cost can be saved.

ARTICLE INFO

Keywords:
Distributed generation
Fire weather index
Geospatial model
Grid resilience
Networked microgrid

ABSTRACT

This paper proposes a strategy for managing wildfire risks and preventing blackouts using microgrids. To demonstrate this approach, not seen in previous literature, we use the power network of Victoria, Australia, in December 2019 as a case study. The Fire Weather Index (FWI) is a crucial indicator of global fire behaviour both spatially and temporally, as proved with its robust analysis within many previous studies. The FWI is applied to a Wildfire-Energy System for the first time, contributing to a higher spatial and temporal resolution to position the wildfire risk in a grid. A novel method is proposed to automatically correlate the wildfire risk index and the power network model using geographical information of the transmission lines. The optimal power flow and grid performances are obtained from a grid model which incorporates wildfire risk distributions. It is shown that a system with installed microgrids can maintain operation under severe fire-related conditions without scheduled or unplanned outages. Finally, a cost-benefit analysis is conducted, which demonstrates that 68% of system costs can be recuperated by implementing networked microgrid solutions.

1. Introduction

In recent years, the frequency of extreme weather events has increased worldwide, in part due to climate change, resulting in significant financial and social losses to both power system operators and consumers [1]. Wildfires are initiated by different causes, either natural (such as lightning strikes) or human (e.g., accidental sparks, or deliberate arsons). The predominant cause of wildfires is different in various regions, e.g., human factors account for about 42.9% of ignitions in Victoria, Australia [2], whereas 95% of ignitions attribute to human activities in California [3]. Fuel flammability, low humidity, and high wind conditions can all increase the probability of extreme wildfire conditions [4]. With increasingly frequent wildfires, heat damage to grid infrastructure can occur and lead to the introduction of further hazards [5]. Specific hazards to the energy infrastructure include sagging conductor lines due to the high temperatures during the wildfire season and flashover events [6].

Wildfire risks to the grid have become an international phenomenon in recent years. For instance, from December 2019 to February 2020, Australia faced an unprecedentedly intense and devastating wildfire season [7]. Multiple wildfires broke out in all states in Australia, particularly in Victoria, resulting in 34 fatalities and the destruction of more than 10 million hectares of land [8,9]. Approximately 20,000 households' power supplies were disconnected at the peak of wildfires during the New Year period in New South Wales [10]. Also, in 2018, a transmission line belonging to California's largest utility, Pacific Gas & Electric (PG&E), started a wildfire that led to the company pleading guilty to 84 counts of manslaughter and destruction of the Town of Paradise [11]. This devastating wildfire caused around $13.5 billion of damage to property, such that PG&E was forced to declare bankruptcy

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[11]. In regions prone to wildfires, managing these low-probability and high-risk events has required frequent short-term disconnections, which affect millions of customers and add indirect social loss on top of physical loss.

The conventional power system has a one-way structure, with power delivered from generation to transmission, distribution, and demand [12]. Along with this structure, long-distance, high-voltage power lines traversing heavily forested areas are particularly vulnerable to wildfires [4]. According to a recent article in the San Francisco Chronicle, physical methods like undergrounding and better insulation of the overhead lines have been outlined by several states to enhance the grid resilience (defined as the ability of a grid to sustain normal operation under extreme conditions) with a greater wildfire risk [13]. Resilience is one of the key grid indicators, which can be improved by network design and physical reinforcements. Network resilience is defined as the ability of a power grid to sustain normal operation when facing high-impact, low probability events like natural hazards [14]. A resilient system should be endowed with fault tolerance, quick response, restorability, and reliability when facing disruptive events [15]. Both the load shedding rate and the line loading rate can be utilised to measure system resilience [16]. In our paper, four grid resilience metrics are utilised to assess the system resilience performance in different scenarios. The definitions, units and selection reasons for the metrics will be discussed in detail in Section 2.5.

The cost of physical reinforcements is prohibitively expensive: it is estimated that it will take over $100 billion for PG&E to underground all its high voltage lines across their entire network (2/3 of California). Besides the significant expense, there is concern about the environmental effects of undergrounding in bio-diverse regions [13].

With an increasing pursuit of more robust and clean grid operations, the regulation and enhancement of grid resilience using renewables have attracted more public attention [17]. One such method is the use of microgrids. A microgrid is a subset of the network that can operate independently from other parts of the network, made up of small-scale distributed generations, local demand, and energy storage systems. In microgrid strategies, various Distributed Generators (DGs) are installed in the vicinity of end-users, such as photovoltaic (PV) panels and small wind turbines [18]. The capacity of DGs can range from several kilowatts to 300 MW [19].

In our paper, various capacities of distributed generators are installed at each node of a transmission network to share the load burden during wildfire seasons. According to regional wildfire risks, parts of the network transmission lines are disconnected, and the corresponding local demands are supported by the distributed generators to avoid load shedding as much as possible. The remaining operating lines in "fire-free areas" keep the power channel between nodal demand and the grid generation unobstructed. In this case, the nodal demand is partially supplied by either the main grid or the local distributed generation depending on the economic benefits (e.g., the real-time electricity price). The two operation modes above can represent the grid connection (i.e., normal mode) and the isolated islanding mode, thus being treated as a potential microgrid method to enhance the grid operation under extreme events.

Jazebi et al., 2020 provided a comprehensive review of previous wildfire management techniques in engineering-related fields. It was found that existing literature mainly focused on how wildfires may physically damage lines in high wildfire risk areas [20,21]. However, wildfire risks can affect grid performance without direct damage, e.g., soot accumulation may lead to current leakage and line off [5]. Solar photovoltaic power is not a recommended local DG source in fire-prone regions since the wildfire smoke negatively affects the power generation – the overall electricity reduction is 7%, with the peak power shedding of 27% in a fire-burn case study in Canberra [22]. Similar phenomena have been found in California and Malaysia – a 30% reduction in average electricity generation in California during September 2020 [23] and 0.43 W power reduction per increment of 1 point Air Pollution Index (API) for Malaysian PV in 2014 [24]. More comprehensive influence factors should be considered in the future. Rhodes et al., 2020 created an optimisation model to mitigate powerline fire risk, based on the Institute of Electrical and Electronics Engineers-Reliability Test System of the Grid Modernization Laboratory Consortium test case in Southern California [4]. Power Shut-off methods were used to allow lines that were important for load delivery to continue to run even with high loading and high wildfire risks, whilst other lines with less load were disconnected at a lower wildfire risk. This control system enabled more load portions to be served in a high wildfire risk period. However, once the overloaded lines exceeded the tolerable time for the protection relay without microgrid supports, it would lead to load shedding and line outages [25]. This method may cause a powerline fire if the highly loaded lines operate for an extended period [6]. Thus, a strategy considering microgrids is motivated to sustainably serve more load without powerline fires and system failure for longer durations.

This paper proposes the novel use of microgrids to manage wildfire risks within power systems without resorting to power outages. As an extensively validated measure of fire potential, the Canadian Forest Service Fire Weather Index Rating System (FWI) is innovatively utilised to describe the wildfire risk distribution over a power grid. The previous study [4] utilised a static wildfire risk distribution model that was spatially partitioned into only three levels based on loosely assembled data from [26]. In comparison, in our study the wildfire risk is measured daily and regionally with exact 'Danger Ratings' to achieve a higher accuracy. In addition, a cost-benefit analysis of the proposed microgrid method is conducted to prove its feasibility and sustainability. The method in our paper is adaptable and can be applied to protect power networks in other fire-prone areas. The Wildfire-Energy System (hereafter the Test System) represents an example case of our model based on a practical grid scenario of Victoria, Australia, in the 2019–2020 wildfire season. The Test System consists of two main components: the Wildfire Index that calculates the wildfire risk distribution for Victoria, and the Grid Model that simulates the power network of Victoria, hereby refer to as the Wildfire Index and the Grid Model. Considering the economic and environmental limitations of the physical reinforcements, network improvements with microgrids are proposed in this paper to enhance the grid resilience during fire seasons.

In Section 2, the methodology to construct the Test System with geographical data is discussed in detail. The overview and dataset sources of the three scenarios are described in Section 3, aiming to explore how overall wildfire risks, FWI line disconnection thresholds and microgrids influence grid resilience. In Section 4, the results for the resilience performance analysis are demonstrated and analysed with four parameters, including line loading, load shedding, system operating costs, and carbon emission factors. The cost-benefit analysis for microgrid solutions is also discussed, and Section 5 summarises the main findings and advises potential future developments to the Test System.

2. Methodology

In this section, we describe the proposed method following the model formulation process. The Wildfire Index calculation and the Grid Model construction are first explained in Sections 2.1 and 2.2. A spatial analysis technique is then described to match the Grid Model with the Wildfire Index using the coordinates of transmission lines (as explained in Section 2.3). In this study, microgrid solutions are utilised to share regional demand when bulk supply is significantly reduced due to wildfires. Designs of microgrids and automatic line control strategies are also discussed in this section (as explained in Section 2.4).

Furthermore, the simulation methods used to assess system resilience are described as the critical analysis of this paper in Section 2.5. Direct Current Optimal Power Flow (DCOPF) has been implemented as the main simulation to calculate the optimal grid solution under system safety conditions, producing various performance indices. Fig. 1 shows the main components and the main steps to obtain grid resilience under

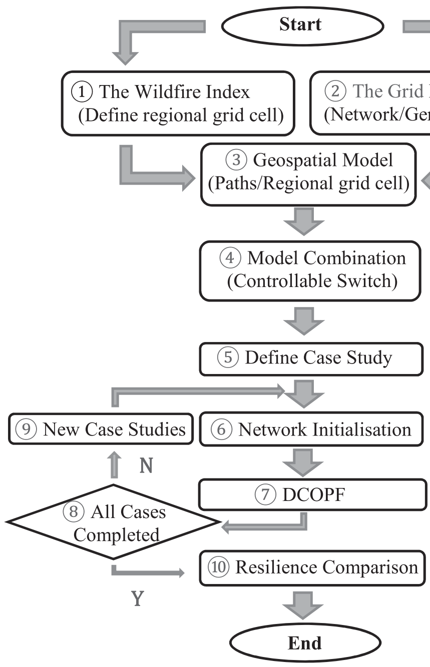

Fig. 1. Main components and construction steps flow chart for the Wildfire-Energy System.

fire risks in our model. This section describes general methods of power grid analysis under wildfire risks for increased replicability and model implementation across other regions of interest.

2.1. The wildfire index

The simulation of the wildfire risk distribution is one of the critical parts for the Test System design. Wildfire risk levels can have substantial simultaneous differences within a large country. Therefore, a better temporal and spatial accuracy of the wildfire risk severity is crucial to model the Test System better.

A weather-dependent risk index was utilised in our study to simulate the wildfire risk distribution during the 2019–2020 wildfire season. The FWI is a meteorological index that is used to evaluate the risk of wildfires [27]. The FWI ingests meteorological parameters such as temperature, wind speed, relative humidity and 24-hr precipitation [28]. The FWI *Danger Rating* (DR) is classified into six levels, and the relationship with FWI is described in Table 1.

An alternative index is the McArthur Forest Fire Danger Index (FFDI), developed based on Australia's wildfire data [29]. According to findings from Dowdy et al., 2009, both FWI and FDI were mostly sensitive to the wind, relative humidity, and temperature. The percentile of the two indices showed a consistent representation under severe fire

Table 1
FWI Danger Rating classification adapted from [28] (upper bound excluded).

Fire Danger	FWI Ranges
Very Low	(0, 5.2)
Low	(5.2, 11.2)
Moderate	(11.2, 21.3)
High	(21.3, 38.0)
Very High	(38.0, 50.0)
Extreme	(50.0, +∞)

conditions [30]. In most cases, FFDI and FWI both offered similar climatological patterns of wildfires and resulted in similar warnings for wildfire disasters [31]. Thus, the wildfire distribution is relatively independent of the index used. Oldenborgh et al. have applied the FWI to analyse the attribution of Australian bushfires [32]. While FWI was originally derived from Canada, it has been shown to be applicable in many different climatic regions (e.g., Mediterranean Europe [33,34]). Therefore, FWI was utilised in this study based on the universality and the availability of the index.

The FWI of each microclimate region is available from the Copernicus Climate Data Store [29] in Network Common Data Format (netCDF) files [35]. A microclimate is defined as a region with specific climate conditions and topographic locations [36]. This paper describes a microclimate as a region with a different wildfire risk feature from neighbouring regions. For the case study area, the whole studied region was divided into 0.25°×0.25° grid cells in line with the spatial resolution of the wildfire risk distribution data. As the geographical coverage of the data is on a global scale, the FWI distribution can be calculated for other regions using the same method [32]. As an example of wildfire risk distribution, Fig. 2 shows the Australian FWI for the 30th of December 2019, highlighting the wildfire risk danger level.

In previous studies, such as [32,33,34], FWI is used as a measure of fire risk irrespective of ignition sources. Determining the actual risk of powerline ignition at a particular FWI value is beyond the scope of this paper as we are unable to quantify the likely occurrence of all possible ignition sources at all locations. This is especially true given a number of ignition sources that are the direct result of human behaviour. In França et al., the FWI was utilised as one of the three main elements to assess the fire-risk-breakdown of the power lines in Northern Brazil [37]. Thus, the FWI was regarded as a reference index here to help determine the proper operating mode of the grid component within the Grid Model to avoid a larger scale outage. In practical power systems, the system operators should design a fire prevention plan considering both the regional FWI and possible ignition sources nearby.

2.2. The grid model

Three main steps to construct the Grid Model are explained in detail in this section. The power network was set up within the Grid Model in Step 1, the power generation information was added in Step 2, and the energy demand distribution was obtained in Step 3. The detailed construction procedures and data sources specific to the Victoria Case study are discussed in detail in Section 3.

It is notable that our model focuses on grid formation and static power dispatch rather than dynamic energy dispatch. Our grid resilience

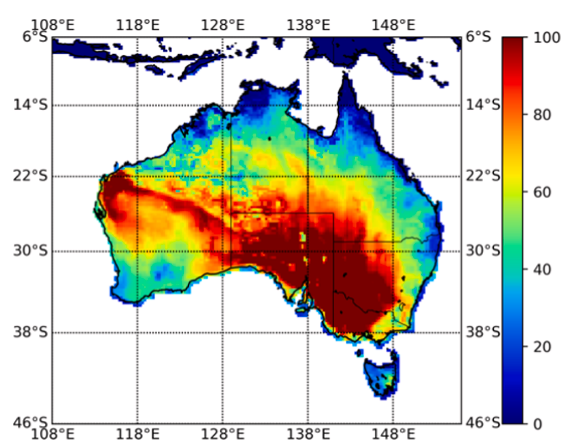

Fig. 2. Australia FWI colourmap on 30th Dec 2019.

analytical parameters are obtained for the worst-case scenario (when the grid is operating at peak load). The current work is assessed with dynamic wildfire risk simulations and grid at peak demand. We only consider wind generation with a capacity factor. However, future work could consider more detailed modelling of local microgrid load profiles, which would allow us to investigate the value of battery storage.

Step 1: Network Assembly

A Keyhole Markup Language (KML) file is a file format to display geographic data containing pinpoint locations and image overlays [38]. As input, raw KML data were downloaded to obtain the geographical and electrical information about transmission lines, substations, and power stations [39]. State and boundary data were imported in the format of shapefiles [40]. The Statistical Area Level 2 (SA2) population dataset [41] was obtained to estimate the regional demand distribution by the Voronoi tessellation method [42]. Then, the operational grid components belonging to National Electricity Market (NEM) zones were sorted based on the information from energy market operators [43]. As an example, the operational grid and the demand proportion served by each node within the state of Victoria are shown in Fig. 3.

Step 2: Generator Dataset

While the power station positions were given in Step 1, technical and economic parameters were assigned to generation information. The technical data of generators were collated, including fuel types and registered capacities. Databases containing the unit technical parameters and operating costs were imported to supplement the information in this step. After filtering generators that did not satisfy the system conditions (e.g., standing exemption of small-scale DGs according to the local authority), a comprehensive dataset that contained all the necessary generation information was obtained.

Step 3: Historical Load and Dispatch

Historical load signals were required to provide the actual demand for the power flow simulation in *Pandapower* [39]. However, most of the public load dispatch data were regional rather than nodal demands divided into smaller clusters. The nodal demand distribution was obtained using the aforementioned method of Voronoi tessellation. Based on the output from Step 1, the nodal demand was attained by multiplying the total demand by the nodal proportion.

Networked Microgrids

In the microgrid scenario, networked microgrids were installed at each node of the Grid Model to enable the regional grid to transform between grid-connection and islanded mode flexibly. Different proportions of nodal demands were served with additional DG integrations to investigate how much load shedding of the Test System can be avoided with various capacities of microgrids. To be more specific, nodal demands were calculated from Step 3. Different nodal demand proportions were then supported with DGs to share the local demand, particularly at nodes isolated due to high fire risk. Finally, the whole system performance was assessed by comparing the result of resilience parameters (Table 2). A cost-benefit analysis was conducted to seek a better trade-off between the cost of load shedding and the microgrid installation solution.

2.3. Geospatial modeling

The length and the trajectory of transmission lines are essential for the Test System, primarily because some electrical parameters (e.g., resistance) are closely related to the line length. Another reason is that knowing the exact path of lines (rather than only start points and end points) is essential for accurate wildfire risk detection of lines that cross multiple microclimates. To complement the Grid Model with network line geographical information, KML files containing multiple coordinates were utilised to describe the line paths with a higher accuracy.

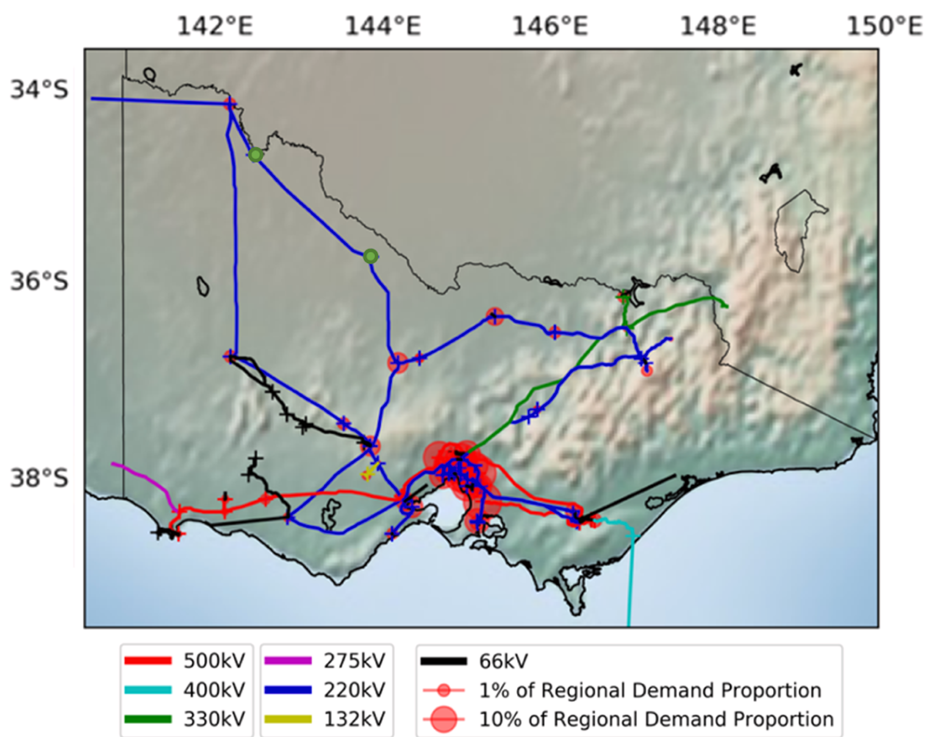

Fig. 3. High voltage transmission network in Victoria, Australia, where “+” represents substations, the size of red circles represents regional energy demand proportion, the two green spots indicate a 220 kV transmission line from Red Cliffs to Kerang, which will be discussed as an example in Section 2.4. (For interpretation of the references to colour in this figure legend, the reader is referred to the web version of this article.)

Table 2
Metrics comparison for resilient system operation (technical, economic, environmental and trade-off).

NO	Standard	Name	Mathematical Expression	Terms	Comment
(a)	Technical	Line Loading Percentage	$\frac{Current_{line}}{Rating_{max} \times df \times parallel}$	$Rating_{max}$: maximum rating df : derating factor $parallel$: Number of parallel lines	Both maximum line loading rate and the system average loading rate are investigated (%)
(b)	Technical	Load Shedding Proportion	$\frac{\text{SD-AC}}{\text{SD}}$	SD : System Demand AC : Actual Consumption	The reduced load divided by the total system demand (%)
(c)	Economic	Short-Run Marginal Cost	$VOM + Fuel_{cost} \times Heat_{rate}$	VOM :Operations & Maintenance Cost	The short-run marginal cost is computed in the DCOPF process (AU$/MWh)
(d)	Environmental	Emission Factor	$\frac{\sum(\text{Emission}_{\text{intensity}} \times \text{Gen})}{\text{Total}_{\text{gen}}}$	Gen: Electricity Generation $Total_{gen}$: Total Generation	System becomes eco-friendly as the emission factor decreases (kg CO_2eq/kWh)
(e)	Comprehensive	Trade-off	Detailed explanation in Section 4		Load shedding cost VS DG cost

To be more specific, the coordinates in the Australian transmission line KML files are with a spatial resolution of 0.001° [44]. Thus, KML files were chosen here.

In terms of spatial information within the Wildfire Index, the original netCDF4 data of FWI were calculated for discontinuous grid cell vertices. To overlay the value over the entire region, each sampling point was first selected as the centre of one grid cell. Then the FWI of this grid region was assumed to have the average FWI of the four surrounding vertices.

2.4. Combining wildfire and grid information

In combining the Wildfire Index with the Grid Model, methods to assess and determine the operational status of grid components are essential. As in most networks, transmission lines, especially high voltage lines, are geographically extended over a large area [45]; long transmission lines may cross different regions with separate and different wildfire risk conditions due to their microclimates. For instance, Victoria has a major transmission line (from Red Cliffs to Kerang), traversing different microclimates as shown and marked with green dots in Fig. 3. Long-extending transmission lines result in difficulties in making well-justified operational decisions as various line segments may have different failure probabilities.

Two main methods have been proposed to define the failure probability of system components that span multiple microclimate regions. The first utilised the weighted-average method: an incremental multiplier of failure rate (IMFR) can obtain the overall failure rate by adding the point-specific failure rates along each line segmentation according to their respective microclimate regions [46]. In the second category, the failure rate for the entire transmission line was determined by the highest failure rate along with any one single point of a line [47].

According to the Australian government, lines with a voltage greater than 66 kV are defined as transmission lines. Those at lower voltages are classified into the distribution level [48]. Thus, only transmission lines with voltage levels over 66 kV were considered in this paper. And the focus was given to cases in which transmission lines cross various microclimate regions. As shown in Fig. 3, most lines crossed different microclimates with different failure rates during the wildfire season. As minor failures can instantaneously have a great impact on the wider high-voltage transmission lines, this paper assumed that the worst failure rate along the line was selected to judge the whole line's failure and following operational modes.

The Test System operated according to simulated information from both the Wildfire Index and the Grid Model. The operation method here is similar to the real-world solution: transmission lines have reclosers installed which can be automatically disconnected if a fault or overload occurs [49]. To isolate the section of the power network under high fire risks and avoid a larger-scale outage, a controllable line-bus switch was set on each transmission line in the Test System [50]. While the worst line failure rate (depending on the worst fire risk exerting on the line) was available, the line operational mode was then controlled by line switches. When any part of the transmission line crossed an area exceeding the preset risk threshold, the switch on the line was automatically disconnected. In Scenario 3, part of the network connected to a disconnected line would then operate in an islanded mode with DGs to reflect the operation of microgrids.

In the line disconnection decision process, the sampling accuracy can be changed according to the resolution of the data. For instance, since the grid cell length was 0.25° in Victoria, the coordinates along each line were extracted in steps of 0.01° latitude to achieve good spatial accuracy. After obtaining the transmission line coordinates, the corresponding FWI grid cell covering each line sampling point was identified. As the FWI of each regional cell had been computed, each coordinate along the line was assigned with a value of FWI.

Finally, the maximum FWI value was selected along each line and compared with the preset FWI threshold under different fire control conditions. A switch was opened within the Grid Model if the maximum FWI along a line exceeded the limit. Similarly, in practice, lines are disconnected to prevent wildfires, followed by customers being disconnected to ensure the power grid is not overloaded during wildfire seasons [51].

2.5. Simulation methods

Grid performances (metrics from Table 2) were obtained from an optimal power flow model incorporating wildfire risk distributions [52]. The Optimal Power Flow (OPF) is the best operating situation of power stations to meet the grid demand, determined by network variables, constraints, and the specific objective of the OPF model utilised. The most common objective for OPF is to minimise operating costs [52]. OPF can be classified into Alternating Current OPF (ACOPF) and Direct Current OPF (DCOPF). ACOPF problems are typically approximated and solved by DCOPF that focuses exclusively on active power constraints due to its linearity and solvability [53].

The DCOPF is a built-in function in *pandapower*. The system completed the calculation procedures if the load and generation achieved balance with all constraints satisfied. According to the parameters of each generator, the optimal power flow followed the objective to minimise the system load shedding in the DCOPF. The Test System simulation was initialised using the wildfire, network, generator, historical load dispatch, and geospatial data. Then, DCOPF was carried out to produce system resilience parameters under different fire conditions.

Different metrics can be utilised as standards in grid resilience assessments, such as line loading percentage, load shedding percentage, increased economic profit, reduced death, ecological impact and so on [16]. The Short-Run Marginal Cost (SRMC) can describe the cost of producing one additional unit of service [54]. In the electricity market, SRMC is computed from the efficiency, operation and maintenance costs (O&M) and the fuel cost [55]. SRMC was utilised to evaluate the economic profit of the system in our study.

In the OPF result, four metrics were chosen for resilience analysis in this paper. The performance parameters are displayed and explained in Table 2, which contains the technical, economic, and environmental standards as well as the measurement units.

3. Case study

In this section, the Test System prototype in Victoria, Australia, is first introduced, and then the details of three scenarios to analyse grid resilience performance are viewed. Of these, the first is to explore how overall wildfire risk levels affect grid resilience. Then two others are presented, i.e., preset FWI disconnection thresholds for lines and various capacities of dispatchable microgrids.

3.1. The test system overview

To better apply the proposed methods to real-world network operations, a real power grid was selected in this paper. As mentioned in Section 1, Australia was attacked by a devastating wildfire from December 2019 to February 2020. Compared to other states in Australia, Victoria has some factors that make it suitable for a case study, such as large transmission networks, highly varying wildfire risks and good data availability. Thus, 'Victoria, Australia' (hereafter 'Victoria') in December 2019 has been selected as the research region of our case study.

Following the three steps explained in Section 2.2, the grid model for Victoria was built. In terms of the input for Step 1, 'Network Assembly', raw KML data from Geoscience Australia were utilised to obtain the electrical and geographical information on transmission lines [44], substations [56], and power stations [57]. State and boundary data in the format of shapefiles were accessed from the Australian Statistical Geography Standard in the Australian Bureau of Statistics [40]. According to the Regional Population Growth Module in the Australian Bureau of Statistics [41], the SA2 population datasets were obtained to estimate the regional demand distribution. NEM zones information were utilised to filter out operational grid components belonging to the Australian Energy Market Operator (AEMO) [43].

Then we moved to Step 2, 'Generator Dataset', the technical data of generators were collated from the Market Management System Data Model (MMSDM) [58]. The National Transmission Network Development Plan (NTNDP) database also contained information about the unit technical parameters and the operating costs [59]. The technical and economic generator dataset was constructed in Step 2.

As for Step 3, 'Historical Demand and Dispatch', the nodal demand proportion was obtained using the Voronoi tessellation method. The nodal demand was calculated by multiplying the nodal proportion by the total demand [58].

Main Components and Parameters

In this paper, the Victoria network was filtered so that only high voltage lines were retained. Thus, only lines with voltage levels over 66 kV were kept to focus on the high voltage system. Power stations with less than 5 MW ratings were also filtered as AEMO allowed standing exemptions for these small plants, which should not be categorised as generators [60]. There were 201 transmission lines within the NEM operational region in Victoria before the filter procedures. The information on the remaining system components is provided in the following paragraph (also displayed in Fig. 3).

There were 72 buses in the Test System with multiple voltage levels of 500 kV, 330 kV, and 220 kV. There were 68 transmission lines in the network, including 16×500 kV lines, 1×330 kV lines, and 51×220 kV lines. 84 power stations were in operation in Victoria at the time of data collection, sourced by brown coal, natural gas, hydro, or wind.

The Test System Formulation and Simulation

A geographical rectangle region that could contain the entire Victoria territory was selected with the latitude range of [-39.25°, -33.75°] and the longitude range of [140.50°, 150.00°]. Since the resolution of FWI reanalysis data was $0.25^\circ \times 0.25^\circ$, the length and width of each grid cell were both 0.25°. Thus, there were 836 grid cells in the selected research region in our model. It is noticeable that one degree represents different distances at different latitudes [61] (e.g., 0.25° denote 28 km at 0°, whereas 22 km at 36°S in Victoria). As the latitude range of Victoria is not too wide, the side length of one grid cell can be regarded consistently as 22 km.

The initial system was simulated based on five days with varying wildfire risks to learn overall wildfire risk impacts on grid resilience in Scenario 1. The FWI line disconnection threshold and the DG proportion were varied in Scenarios 2 and 3 to explore how they may affect system resilience.

3.2. Scenario overview

To start with, the original test system without microgrid integration was implemented based on the five-day data with different levels of wildfire risks. Different wildfire risk conditions can negatively impact line conductor temperatures and flowing current capacities [14]. Thus, the relationship between energy system resilience and the overall wildfire risk severity was studied in Scenario 1. The overall wildfire severity rose throughout December 2019. Therefore, five days were selected as these days can evenly represent the wildfire risk severity level growth from the lowest to the extreme in December (1^{st}, 3^{rd}, 5^{th}, 18^{th}, 30^{th}, December 2019). Fig. 4 displays various wildfire risk levels on the five selected days. The detail and the result analysis of each scenario will be discussed in Section 4.

The setting of FWI line disconnection thresholds may affect the system operation safety and effectiveness. To be more specific, each transmission line has a calculated FWI value, and more lines will be disconnected as the FWI disconnection threshold is set at a lower value. A lower FWI line disconnection threshold means achieving a stricter fire risk control circumstance. Scenario 2 aimed to explore how the FWI line disconnection threshold affected power grid resilience under different fire control conditions.

As the main objective of this paper, microgrid solutions were applied to mitigate the system burden during the wildfire season. As previously mentioned in Section 2.2, power demand at each node was obtained from the historical grid dispatch database [39]. A previous grid reinforcement project has proved that 75% of grid demand can be supported by microgrids, feasibly maintaining a normal operation [62]. In Scenario 3, the installation capacity of DGs was based on the node load in the Grid Model. Thus, 0%, 25%, 50% and 75% of the node load were selected as renewable capacities added at each node, respectively. The outage and microgrid costs were analysed and compared in this scenario.

4. Results and discussion

The results are analysed through technical, economic, and environmental aspects for each scenario. As mentioned in Table 2, four performance indices are obtained and assessed in each scenario, including system line loading percentage, load shedding rate, system operating cost and emission factor.

There were different operating cases defined for each scenario. In Scenario 1, five operating cases were selected from different days, representing different system fire risk levels. Three operating cases were set up in Scenario 2 with various FWI disconnection thresholds for power lines. In Scenario 3, four operating cases were defined based on various proportions of microgrid integration to the Test System.

4.1. Scenario 1 overall wildfire level influences

In Scenario 1, the Test System was simulated with different levels of wildfire risks based on five-day data in December 2019. Both the average FWI and the maximum FWI in the Test System gradually rose from the operating case for 1^{st} December to the operating case for 30^{th}

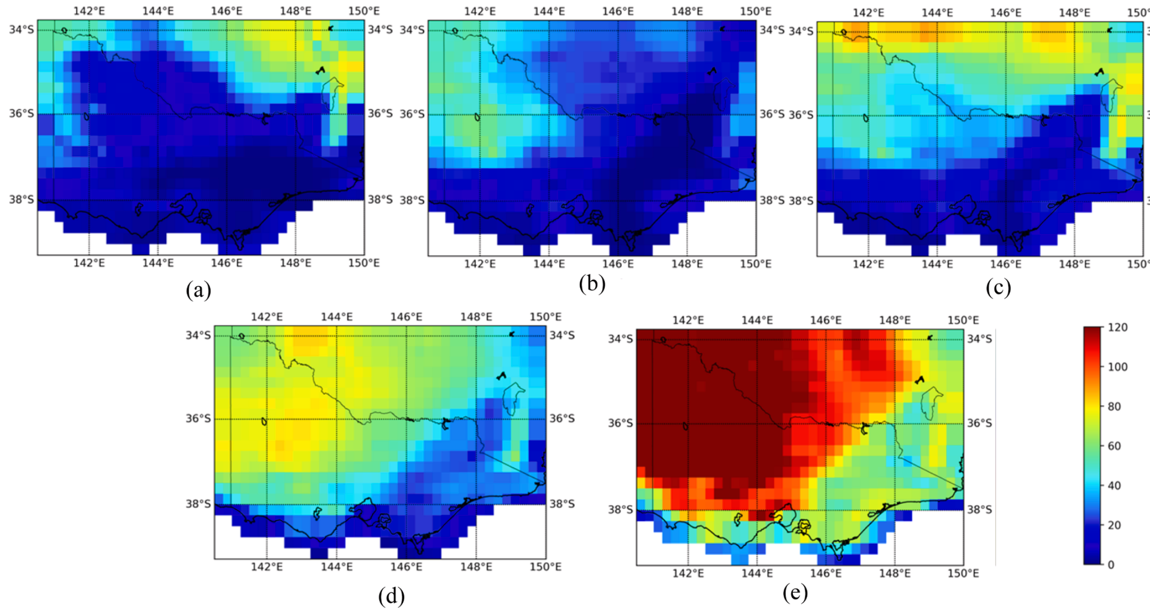

Fig. 4. Scenario 1: FWI colourmaps for five selected days in the 2019–2020 fire season in Victoria, Australia to explore the relationship between overall fire severity and grid resilience (1st, 3rd, 5th, 18th, 30th Dec 2019). An animated video displaying the dynamic FWI during the 2019–2020 Fire Season in Victoria, Australia, is linked here.

December. Since the demand may impact system resilience, grid demands of the following four operating cases were scaled down to the same for 1st December to control the variables (the total system demand).

Regions encounter an extreme wildfire risk if the FWI is greater than or equal to 50.0 [29]. In other words, the transmission line is likely to cause powerline ignition in this situation. Therefore, lines sitting in a grid cell with 50.0+ FWI were pre-disconnected automatically in Scenario 1.

Various lines were switched off as different numbers of lines exceeded the preset FWI threshold (50.0) in the five operating cases. The number of disconnected lines after the OPF simulation remained the same as before if there was no vast load shedding. However, compared to the initial number of pre-disconnected lines, due to a high FWI value, more lines were forced to become out of service if they violated the system safety conditions during the OPF simulation process. For instance, the initial FWI disconnection condition automatically switched off five lines in the operating case for 5th December. In contrast, the final disconnection rose to 22 out of 68 lines, as shown in Table 3, resulting in a large-scale blackout. Without the support of local DGs, large-scale outages can be more frequent due to higher wildfire risks.

As for the first evaluation metric, there was a slow growth in both the average and the maximum line loading percentages from 1st (85.88%, 131.76%), 3rd (86.27%, 149.23%) to 5th (86.63%, 163.64%). It is notable that the system loading sharply turned to drop in the last two days. The system loading was closer to zero in the next two operating cases as more lines were disconnected than pre-disconnected, causing a large-scale outage.

Table 3
Number of disconnected lines in Scenario 1. (Pre-OPF are lines switched off due to the exceeding of the preset high fire risk threshold before the OPF operation; post-OPF are regional power outages due to safety boundary violation after the OPF implementation).

Day	FWI Disconnected (Pre-OPF)	Actual Disabled (Post-OPF)
1st Dec 2019	1	1
3rd Dec 2019	2	2
5th Dec 2019	5	22
18th Dec 2019	17	62
30th Dec 2019	68	68

Moving to the second evaluation metric, the load shedding and the remaining load in Scenario 1 are displayed in Fig. 5. More lines were automatically switched off as the wildfire risk level increased, resulting in more load shedding. Nearly 100% of the load was curtailed in the operating case for 30th December.

The third evaluation is to assess the total and the unit system operational cost. As the wildfire risk developed, the total cost of operation gradually declined since the remaining operational grid was greatly curtailed due to a higher fire risk. Though the total amount decreased, the SRMC rose as the served demand dropped at a higher rate.

The Value of Lost Load (VoLL) represents the cost of disconnection to

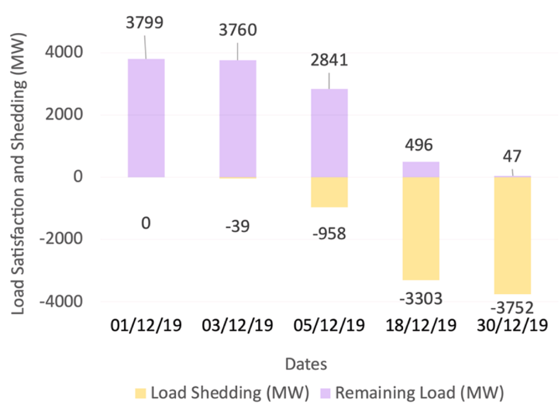

Fig. 5. Load shedding comparison for days with elevated fire conditions in Victoria, Australia (Scenario 1).

customers [63]. It should be noted that VoLL was excluded from the simulated result of SRMC in all scenarios since VoLL can vary largely by season, time of the day, end-user demand and customer type (i.e., the VoLL for public infrastructures like hospitals is higher as the indirect loss for a power outage there is higher). VoLL was not necessarily used in the OPF simulation as the main objective of the OPF was to achieve minimum load shedding. However, the VoLL was still utilised in the cost-benefit analysis since it generally contributed to a significant cost increment [64].

With regarding to the fourth evaluation metric, in Scenario 1, there was no newly integrated renewable source, thus the generation fuel types determined the system's overall emission factor. The unit emission factor measured in kg CO_2eq/kWh was mainly decided by the actual load consumption in this scenario. Overall emissions became lower from the start to the end of December due to the operational generation decreasing gradually under higher fire risks. As for the unit emission factor, the unit emission factor increased by 98.76% from 1st December to 30th December, as nearly all load was eventually shed. The grid became more polluting per kWh as the wildfire risk rose.

4.2. Scenario 2 FWI line disconnection threshold

In Scenario 2, the Test System based on historical data from 1st December 2019 was tested with different FWI disconnection thresholds for power lines. According to the *Danger Rating* classification in Table 1, the FWI disconnection thresholds were set at extreme (50.0), very high (38.0), and high (21.3) in three operating cases, representing the fire control condition becoming stricter in Scenario 2.

Regarding the first evaluation metrics, both the maximum and the overall line loading percentages went up as the FWI disconnection threshold declined. Among the three operating cases, the average loading percentages retained the same order of magnitude (around 86%). In comparison, the maximum line loading gradually rose from 131.76% (operating case with the FWI threshold of 50.0) to 163.64% (operating case with the FWI threshold of 21.3) as more lines were disconnected due to a stricter limit of fire control.

For the second evaluation metric, as the FWI line threshold decreased, the load shedding increased as 7% of lines were pre-disabled in the third operating case, and the rest of the Gird Model could not hold the burden. The system maintained regular operation in the first two operating cases (with FWI thresholds of 50.0 & 38.0) since only one or two lines of 68 were switched off. However, the system load was sharply shed (25.21%) as five lines were pre-disconnected in the third operating case (with an FWI line disconnection threshold of 21.3).

The third evaluation metric is displayed in Fig. 6. The total and unit operating costs in the first two operating cases (with the FWI thresholds of 50.0 and 38) remained the same since there was no load shedding in the first two operating cases, and the actual consumptions were the same. However, the total system operating cost dropped, and the unit operating cost rose once there was a load shedding, as shown in the third operating case. Thus, under a stricter fire risk control limit, the lower the FWI line disconnection threshold, the higher the unit cost.

Regarding the total system emissions, it remained at the same level as the threshold decreased. The unit carbon emission became higher as the actually served demand decreased from the loose fire control operating case (with the FWI threshold of 50.0) to the strict one (with the FWI threshold of 21.3).

Either an FWI of 38.0 or 50.0 can be selected as the disconnection threshold to prevent powerline wildfires which will not affect the normal operation of the Victoria system. The specific FWI threshold value will be judged by the actual needs in the wildfire control levels. If a greater requirement of wildfire control is expected, demand-side response (DSR) services should be integrated so that 100% of the load can be satisfied.

4.3. Scenario 3 networked microgrids

In Scenario 3, dispatchable energy sources like DGs were integrated into the network with different capacity levels to mitigate load shedding. 0%, 25%, 50% and 75% of the node load capacity were injected with DGs at each node of the Grid Model in the four operating cases, respectively. In Scenario 3, the Test System based on historical data from 12th December 2019 was utilised since the Test System without microgrid support on this day had a load shedding of around 70% due to high wildfire risks. Various proportions of microgrid capacities were expected to alleviate the electrical outage to different extents. Cost-effectiveness was also evaluated and compared between load shedding compensation and microgrid connections budgets.

To begin with the first evaluation metric, Fig. 7 shows the maximum and the average line loading for four operating cases. As the DG capacity went up, the maximum and the overall system loading percentages decreased by 29.8% and 53.1%, respectively. The DG installation shared part of the local load, which led to a lower grid burden.

With the FWI threshold of 50.0 set in this scenario, 14 lines were switched off automatically to prevent large-scale outages due to fire control requirements before the OPF simulation process. Without microgrid supports, there would be substantial load shedding in the original network. In the first operating case without DGs, 36 more lines were indirectly disabled after the OPF simulation due to the 14 pre-disconnected lines. It was notable that no line was indirectly disconnected during OPF once DGs were installed to match 25% of the node

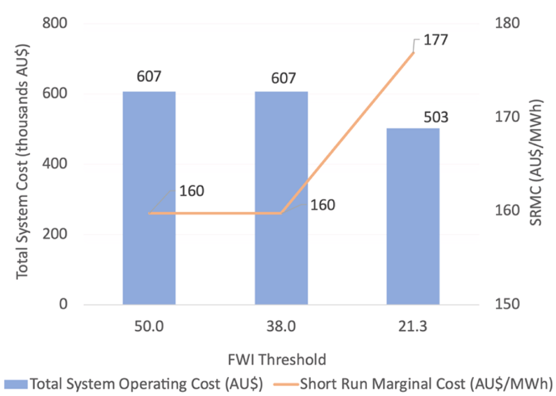

Fig. 6. System operating cost and SRMC with different fire control conditions. FWI thresholds set for transmission line disconnections at 50.0, 38.0, and 21.3, representing the fire control condition becoming stricter in Scenario 2.

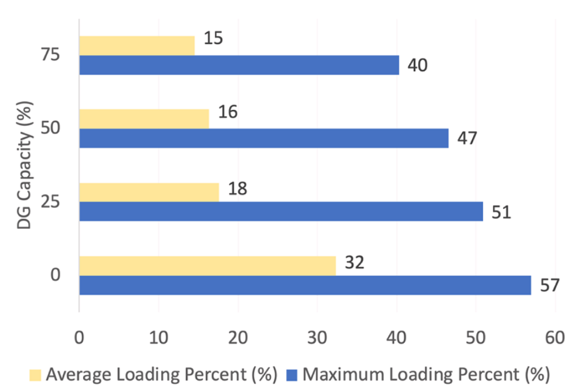

Fig. 7. Average and maximum system line loading percentages with various capacities of DG installation at each node in the grid (Scenario 3).

loads. As the DG integration level increased at the step of 25%, the load shedding gradually decreased (69.33%, 50.47%, 37.80%, 21.67%).

The Average Mitigating Rate (AMR) of load shedding between operating cases was obtained to assess how much load was recovered by DG integration. The method to calculate the rate is given in Eq. (1).

$$AMR = \frac{RL_{2nd} - RL_{1st}}{TSD} \times 100\% \tag{1}$$

where RL_{2nd} is the remaining load in the latter case (the 2nd, 3rd, and 4th operating cases), RL_{1st} is the remaining load in the former case (the 1st, 2nd, and 3rd operating cases), TSD is the total system demand.

The average mitigating rates between the four operating cases were 18.86%, 12.67% and 16.13%, respectively. The overall average mitigating rate was 15.89%, lower than the additional DGs (25%) between cases. Primarily because DGs only undertook the local demand at each node when the node was isolated. In addition, there were transmissional power losses. Thus, the AMR was not just equal to 25% between every two operating cases.

Regarding to the economic evaluation in Fig. 8, the total system operating cost in the first column was relatively lower since 70% of the load was shed in the first operating case without microgrids. In the subsequent three operating cases, there was a surge of 9% in the total system cost first. Then it gradually decreased as cheaper DGs were connected (the O&M cost comparison of DGs and fossil fuel plants will be discussed in Section 4.4). The increase in the total system cost was caused by the system recovery after DG integrations.

The average system operating cost decreased as more local generations came onto the network. For one reason, the overall system operating cost decreased since the SRMC of renewables was much lower than the centralised fossil generation. In addition, the scale of actual consumption recovered as the DG developed. As displayed in Fig. 9, the total and unit emissions decreased as more renewable DGs were used, and the actual consumption rose. Both the unit operating cost and the unit carbon emission decreased as more DGs were used.

4.4. Cost-benefit analysis for microgrid solutions

There are various natural resources for renewable energy in Victoria, including wind, hydro, solar, and bioenergy. The existing widely distributed onshore wind farms and ongoing offshore wind farm projects have proved the feasibility of wind power utilisation in Victoria [65]. Victoria is an excellent site for wind power generation with an average wind speed measured at 6.5 ms^{-1} [66].

In this paper, we propose hypothetical planning of renewable utilisation in Victoria. Both wind and solar resources are abundant in Victoria. A demonstration of renewable resource distribution in Victoria is shown in Fig. 10. Referring to the Victorian transmission network in

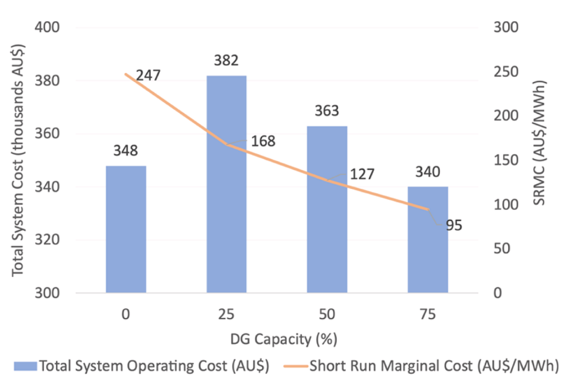

Fig. 8. System cost and SRMC with various capacities of DG installation at each node in the grid (Scenario 3).

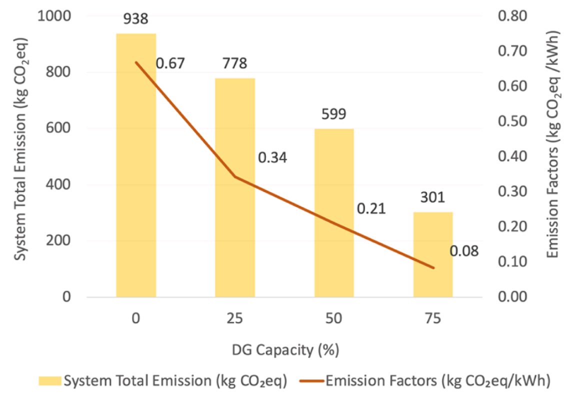

Fig. 9. System emission factors with various capacities of DG installation at each node in the grid (Scenario 3).

Fig. 3 and the FWI maps in Fig. 4, wind resource distribution is highly colocated with both the fire risk and the network distribution than solar power. Furthermore, there is a positive correlation between wind speed and wildfire spread [67], i.e., fire-prone areas are likely to have greater wind power potential. There is a relatively high coincident distribution between the wind abundance and the severe fire risk. In addition, wind power operates more reliably diurnally than solar power. As mentioned in Section 1, wildfire smoke can negatively affect solar generation efficiency. Therefore, we would select wind as the DG source as an example here [68,69].

The microgrid strategies can enhance system resilience by reducing load shedding during the period of high wildfire risks. Then, the financial losses brought by the load shedding can be eased by microgrid installations. However, the installation of the local DGs requires both the capital investment and the O&M cost. The trade-off between the saved cost for load shedding and the lifetime budget for DG installation is assessed in this section.

The system costs before and after the DG installation were compared based on Eq. (2).

$$SO_{cost} = TS_{cost} + VoLL + DG_{cost} \tag{2}$$

where SO_{cost} is the Test System overall cost, TS_{cost} is the total system cost which can be obtained from the OPF; $VoLL$ contains the economic impact of load shedding (through multiplying the unit VoLL cost by the load shedding); Levelised Cost of Electricity (LCOE) assesses the cost of generation for a generator over its lifespan, considering the capital cost and the O&M cost together [70]; DG_{cost} is calculated by multiplying the DG capacity by the LCOE of a wind turbine in Victoria.

According to the Australian Energy Regulator [71], the average electricity price for the Victoria network was AU$84/MWh in 2019. Referring to the latest 2021 economic analysis report about power grids in the NEM, the NEM's Market Price Cap of AU$15,000/MWh is almost the highest in the world [72]. Thus, we assume the VoLL induced by outages in the scenario without DGs amounted to AU$15,000/MWh as an upper limit here. According to statistics from IRENA (International Renewable Energy Agency) [73], the LCOE of a wind turbine was assumed to be AU$64/MWh. The capacity factor of wind turbines was assumed to be 41% [74], which should be considered in the real cost of DGs, as expressed in Eq. (3).

$$DG_{cost} = (DG_{gen} \div CF) \times LCOE \tag{3}$$

where DG_{cost} is the project cost for DG installation, DG_{gen} is the DG generation, CF is the capacity factor.

The data from Scenario 3 were analysed in Table 4, with various proportions of DG connections (the total system demand was 4,587

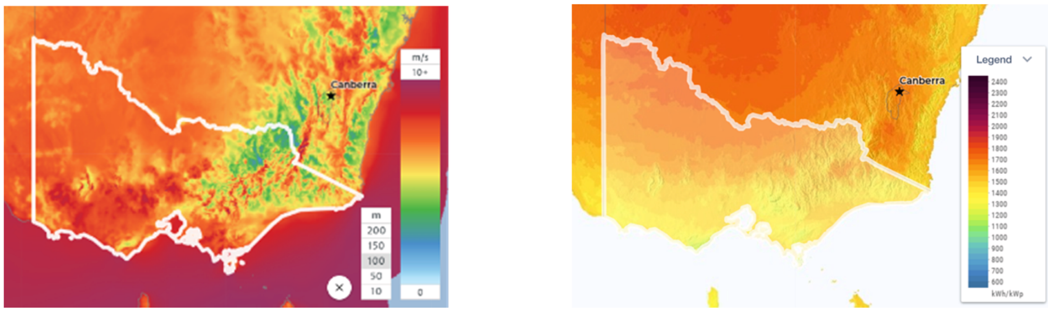

Fig. 10. Distribution maps of renewable resources in Victoria, Australia. Left: mean wind speed (ms^{-1}) [68]. Right: mean PV power output (kWh/ kWp) [69].

Table 4
Cost analysis between intentioned outages without DGs and different proportions of DG installation plans in Scenario 3.

DG Penetration (%)	DG Capacity (MW)	DG Cost (AU$)	Load Shedding (MW)	VoLL (AU$)	Operating Cost (AU$)	Overall Cost (AU$)
0	0	0	3,180	47,700,000	348,000	48,048,000
25	1,147	179,000	2,315	34,725,000	382,000	35,107,000
50	2,294	358,000	1,734	26,010,000	363,000	26,373,000
75	3,440	537,000	994	14,910,000	340,000	15,250,000

MW). The calculation was based on Eq. (2). The DG_{cost} went up as more wind turbines were connected to the system. VoLL represented the economic impact caused by load shedding, which was mitigated as more DGs were integrated. The total system operating cost was obtained directly from the OPF simulation, reflecting the system operating cost in various circumstances. The overall cost considering all above was summed up in the last column. The total economic impact was alleviated as more DGs were installed in the Test System. Compared to the initial system, around 68% of the overall cost was eased when the local DGs supplemented 75% of nodal demand. The considerably high VoLL in NEM took the dominant role here as a leading factor in overall system cost saving. Thus, the local renewable generation method was considered a financially viable solution to achieve a more resilient power network in Victoria, Australia.

4.5. System summary

Among the three scenarios, factors that affect system resilience, economy and environment were simulated and investigated, i.e., the overall fire risk level, the FWI line disconnection threshold and different proportions of microgrid installations.

With regard to power system load shedding, DG produced generation mitigated the curtailed demand in a financially feasible way. The unit operational cost was mainly affected by the consumed system demand and the total system cost. The higher the DG proportion, the lower the unit cost. The unit carbon emission factor mainly depended on the served energy consumption, calculated from the OPF simulation. The summary of effects is given in Table 5. (where '+' represents an increasing variable and '−' represents a declining variable)

Table 5
The Test System performance comparison (where '+' stands for an increasing trend and '−' represents a declining trend).

Performances	Scenarios		
	I	II	III
Variable Tendency (+)	Fire Risk	FWI Threshold	DGs
Line Loading Percentage	+	−	−
Load Shedding	+	−	−
Unit Operational Cost	+	−	−
Unit Emission Factor	+	−	−

5. Conclusion and future work

This paper has proposed the use of microgrids as a novel strategy to mitigate powerline fire risks without the need for blackouts. The power system resilience performance was assessed in high wildfire risk regions. Victoria, Australia, in December 2019 was selected as an example case study. This paper was driven by the practical need to protect power systems and reduce economic and social loss during a high wildfire risk period. The results obtained from the simulations have shown how can intentional power shut offs and microgrids enhance power system resilience in a financially feasible way. The validated FWI was first utilised in a weather-affected power system, which improved the spatial and temporal resolution of wildfire risk positioning in power grids.

Methodologies to assess grid resilience and to build the weather-affected energy system were introduced and discussed. The controllable power line switch played the role of the bridge between the Wildfire Index and the Grid Model, which was automatically disconnected as the line FWI exceeded the preset thresholds under different fire control conditions. The methodology does not exclusively apply to the Test System in Victoria but can be adjusted to other fire-prone regions, supporting the use of the applied methods across various spatial domains and wildfire-prone network grids.

Three scenarios were presented to investigate how the Test System was influenced by three main variables, i.e., the overall wildfire risk level, the FWI disconnection thresholds for power lines, and the microgrid proportions.

The results showed that the overall line loading percentage was positively correlated with the wildfire risk. The line loading percentage declined as the FWI threshold or the DG proportion went up. Secondly, the change of load shedding had an opposite tendency with the FWI threshold and DG capacity, and load shedding rose as the wildfire risk became higher. As for the unit operational costs, only the severity of wildfire risk negatively impacted costs. The unit carbon emission factor was eased as the FWI thresholds or the DGs increased, but it was worse as the wildfire risk became more severe.

A higher value in the FWI disconnection thresholds and DG capacities eased system operational stress, both economically and environmentally. According to the cost-benefit analysis, it was proved that the microgrid solution could save 68% of the overall system cost. It provided both a way to improve system resilience economically and feasibly integrate more renewables within the grid.

FWI data are currently measured daily, at noon Local Standard Time worldwide. However, power systems are usually assessed once every half hour. A more accurate model can be obtained as the temporal resolution of the weather data becomes higher. An FWI curve with a temporal resolution at half-hour intervals can be linearly formed by FWI related parameter curves.

Since the *pandapower* is not directly a time-dependent tool for power simulations, no time domain parameter is set in the default power flow calculations. The current system can only model instantaneous and static operations. More frequent monitoring of the grid operation is therefore preferred. More scenarios can be designed in a continuous-time model when energy flow is created rather than just instantaneous power flow, e.g., scenarios about energy storages.

While our paper only assesses the transmission network with voltage levels greater than 66 kV, the model can be applied to a lower voltage level network to explore electrically caused wildfires and wildfire-induced electrical faults in distribution networks in the future.

In conclusion, the high-resolution wildfire-affected power grid combining the FWI, intelligent power line disconnection strategies, and microgrid solutions was proposed in this paper. It has been demonstrated that microgrids have the potential to improve grid resilience performances economically. The methods developed for weather-dependent power system modelling in this paper can be used to investigate how microgrids improve power grid resilience in the face of other extreme weather events, such as floods and hurricanes in the future.

CRediT authorship contribution statement

Weijia Yang: Methodology, Software, Writing – original draft, Writing – review & editing. **Sarah Sparrow:** Writing – review & editing, Methodology, Supervision. **Masaō Ashtine:** Writing – review & editing, Supervision. **David Wallom:** Conceptualization, Writing – review & editing, Supervision. **Thomas Morstyn:** Conceptualization, Methodology, Writing – review & editing, Supervision.

Declaration of Competing Interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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Appendix A. Supplementary material

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Microgrids against Wildfires: Distributed Energy Resources Enhance System Resilience

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In recent years, countries around the world have been severely affected by catastrophic wildfires with significant environmental, economic, and human losses. Critical infrastructures, including power systems, have been severely damaged, compromising the quality of life and the continuous and reliable provision of essential services, including the electricity supply.

When such disasters strike, the impacts usually go beyond what the system has been designed to withstand, potentially leading to prolonged power outages for large numbers of customers and critical loads in the system. These impacts are expected to only get worse as a result of climate change-driven high temperatures in wildfire seasons as recently highlighted in California, Australia, Chile, Brazil, Portugal, Italy, and Greece.

Power system planners have traditionally attempted to boost the resilience of critical electrical power infrastructure against such high-impact low-probability events by making the network redundant or stronger to withstand their severe shocks. Nevertheless, recent wildfires reiterate that alternative solutions need to be explored and deployed for the holistic provision of robustness, preparedness, and recovery. Distributed energy resources (DERs) and microgrids arise as attractive decentralized options for providing a means for riding through and recovering from the catastrophic impacts of wildfires. They represent localized energy solutions that are potentially less exposed to the wildfire effects compared to network assets.

This article aims to tackle a set of key relevant questions:

- What is the role of DERs and microgrids to protect the system against wildfires?
- How can microgrid operational capabilities improve traditional reliability-driven approaches for making the network more resilient?
- How can planners assess investments in DER portfolios to achieve an effective trade-off between DERs and network planning?
- What are the regulatory and policy barriers in adapting such hybrid resilience enhancement portfolios against wildfires?

This article provides an overview of real-world evidence to understand the potential contribution of DERs and microgrids against wildfires. It presents a holistic framework for assessing and quantifying the role of DERs in operational planning and investment decision-making to enable additional robustness and flexibility in a system exposed to wildfires.

Real-world examples

Looking at real-world examples can help explore the potential benefits of DERS and microgrids to improve power system resilience under wildfire scenarios. Using challenging situations where these resources have mitigated or resolved operational issues can help fire prevention stakeholders better understand the feasibility and desirability of their practical application to wildfire resilience.

California

Conventional means of wildfire mitigation associated with the transmission system have been found lacking. For example, in California, following years of major wildfires that included interactions with the electric system, distribution companies are deploying preventive de-energization of the grid during hot, dry high-wind conditions to prevent the power system from igniting wildfires. Though unpopular by those losing service, these outages, known as public safety power shutoffs (PSPSs), reflect that the highest priority of any power network entity is safe operation despite the significant costs.

Without adequate mitigating measures, such as local backup generation or microgrids, this can lead to customers being left without essential services, potentially for days. The hot, dry weather is common in the late summer and fall. The high, turbulent, and dry wind tends to trigger PSPS events, which typically last one to two days but can stretch to several days in hard-to-restore areas. PSPSs act as an emergency measure in place of longer-term investments such as reconductoring, reinforcement, undergrounding, or introduction of new technologies such as distributed storage.

The reason such disruptive actions become necessary is the extreme cost and devastation wildfires can cause when started by grid failures. One notable example was the Camp Fire on Nov. 8, 2018, in the northeast of the state. This wildfire, caused by the failure of a hook carrying a conductor, led to an estimated $17 billion (USD) in damages, including 85 fatalities, 18,804 lost structures, 620 km^2 of burned area, and billions of dollars in fines and liabilities for Pacific Gas & Electric Company (PG&E).

The company fell into bankruptcy following a history of similar, damaging events. Its stock price fell by 66% over 13 months, although it was able to exit bankruptcy in June 2020 after agreeing to a range of settlements with government agencies, insurance companies, and other claimants. A victims' fund was established with $5.4 billion in cash and 22% of PG&E's stock. PG&E is undertaking a safety program that is expected to cost about $6 billion during 2021 and 2022 and has proposed a long-run goal of undergrounding about a tenth of its system, about 16,000 km of lines, for $15 billion to $20 billion. Even critics contest this estimate as too low since much of this work would be in remote, unpopulated, and rocky areas.

In 2021, PG&E also began various other programs to mitigate the impact of outages, such as distributing batteries or subsidized generators to vulnerable customers. On the other hand, widespread use of local generators can be a hazard and damage air quality. Also, if fuel is poorly or unsafely stored in high fire risk areas, it could act as an accelerant. The transport of replacement fuel during wildfires can also be hazardous and unreliable. Consequently, sites wanting high resilience often invest in large underground storage.

Given California's history of wildfires associated with power grids and increasing propensity to use PSPSs, independent microgrid technologies being used by both communities and individual customers in the "wine country" appear increasingly attractive.

Blue Lake Rancheria (BLR) has a demonstration microgrid implemented by the Blue Lake Tribe together with Humboldt State University (Figure 1). The microgrid includes 420 kW of PV, a 500 kW/950 kWh battery bank, and a 1 MW backup generator, all connected to the PG&E distribution grid at 12.5 kV through a computer-controlled circuit breaker. A fueling station and attached convenience store form a second microgrid with PV, batteries, and some building system controls. The main microgrid system was not initially designed to be a preventive measure against wildfires, but was motivated by the tribe's sustainability culture and potential cost savings of about $200,000 (USD) a year.

Figure 1: Overview of Blue Lake Rancheria casino complex.
(source: Schatz Energy Research Center, Humboldt State University).

As PSPSs are increasingly necessary, customers connected to a microgrid retain access to services and supplies, such as fuel, ice, internet connection, electronic-device charging, and ATMs. Also, the Blue Lake Tribe's event center and hotel can house vulnerable evacuees in an emergency. The microgrid acts as a hedge against failures of the bulk transmission system and supports the wider resilience efforts to control wildfire risk as part of a portfolio of wider actions, which may be taken by planners and operators. The hotel microgrid was first activated for a fire threat in October 2017 (Figure 2). The microgrid islanded when a small brush fire started nearby, and the hotel acted as a shelter for evacuees and a command center for emergency crews.

Figure 2: Fire Near Blue Lake Rancheria.
(source: Redheaded Blackbelt, 8 October 2017).

Regulatory Response

Microgrid deployment has a recurring pattern. They are installed for a variety of reasons, but after they exhibit excellent resilience performance during an emergency, they become promoted primarily for resilience. Following Superstorm Sandy in 2012, microgrids became heavily promoted for community safety in the northeastern United States. Several states have microgrid deployment programs, such as the New York Prize. California similarly had a notable microgrid research program in place, including BLR described above, but relatively slow deployment beyond the demonstration phase. Fires, though, have proven to be this state's microgrid motivator. A few examples of notable resilience performance, including BLR, pushed microgrid development to the fore to mitigate the consequences.

In September 2018, the California Legislature passed SB 1339. This bill requires the California Public Utilities Commission (CPUC) to address some of the barriers impeding the deployment of microgrids. Californians had recognized the severity of the deteriorating fire situation, so the CPUC made its first order of business establishing exemplar microgrids such as BLR that could contribute to resiliency before the summer of 2020. Companies were ordered to:

- develop and implement standardized pre-approved system designs for interconnection of resiliency projects that deliver emergency services
- develop and implement methods to increase simplicity and transparency of project approval; and
- prioritize interconnection of resiliency projects for key stakeholders

Further, several temporary mobile substation generator projects were identified, and PG&E was encouraged to develop them as soon as possible. A community microgrid program was also established.

During the second phase, in January 2021, the CPUC addressed regulatory barriers to microgrid deployment. Notable was the requirement that a limited number of microgrids be permitted to serve neighboring sites' critical loads while not being subject to utility regulation. This move weakens a historically formidable barrier to microgrid development, namely that the microgrid might then be considered a public utility and be subject to overly burdensome regulation. Utilities were also directed to develop standard microgrid tariffs, pilot demonstration projects, and an incentive program.

Most recently, in July 2021, the CPUC suspended a key provision of tariffs to allow a microgrid to be charged for the required utility provision of backup to the microgrid's generation under some circumstances. The CPUC intends to wade into the controversial topic of main grid provision of fallback for microgrids.

Other examples around the globe

Greece

Other noticeable examples of the deployment of DER to support reactive recovery from wildfires include that from Greece, where severe forest fires between Aug. 24 and Sept. 7, 2007, caused considerable damage to the power system with 2,500 burnt poles and disrupted supply to 90,000 customers. The restoration of over 20% of affected customers' electricity supply took more than five days.

In response to this, distributed energy systems, including mobile diesel generators of between 50 and 130-kVa, were used for restoring power supply to parts of the distribution network, forming ad-hoc low-voltage microgrids. Had microgrids been more widely deployed or more extensive sets of resources been available, such extreme recovery times may have been significantly ameliorated. The addition of DERs, such as solar photovoltaic or micro-wind, could also serve to expand the capacity of microgrids, particularly in regions with large solar resources such as Greece and southern Europe more generally.

Following an extreme heatwave with the highest temperatures reaching 47.1 °C (116.8 °F) in August 2021, a series of wildfires erupted, where 125,000 hectares of forest and cultivable land and dozens of homes burned for more than three weeks. The number of fires was 26% above the average of the past 12 years, and the area burned was bigger on average by 450%. The largest wildfires were in Attica, Olympia, Messinia, and the most destructive in northern Evia, with over 50,000 hectares burnt, which is nearly a quarter of the island. Figure 3 shows the wildfires in Greece according to the NASA wildfire tracker from Aug. 2-8, 2021. Figure 4 shows an example of some of the mobile generators being deployed.

Figure 3: Wildfires in Greece from Aug. 2- 8, 2021 (source: NASA wildfire tracker).

Figure 4: Use of mobile generators for restoration (Courtesy: Public Power Corporation, Greece).

In all areas, network damages were extensive. In Evia, 7 MV lines feeding electricity to 13.000 consumers were destroyed. In Attica, 9 MV lines were affected that electrify 38,000 consumers.

Twelve mobile generators with a total capacity of 2.12 MW were used to provide the essential electricity needs before network restoration.

Despite the severity and geographical dispersion of these damages, the Greek DSO (HEDNO) managed to restore electricity to 98% to 100% of the affected clients within 10 days. The only exceptions concerned individual houses and small remote settlements. This fast recovery would not have been achieved by restoring the network alone. Mobile diesel engines were extensively used at secondary substations to supply parts of undamaged LV networks and supply individual installations. Diesel units were also installed in all critical water pumping stations and in dispersed locations to supply parts of the healthy networks.

Australia

In Australia, the Resilient Energy Collective is using prebuilt equipment to restore supply in communities on a micro-scale following bushfires. This is a more responsive and reactive approach to mitigate the impacts of wildfires, but it could be vital to restoring life-critical loads, especially in hot regions which can suffer extreme heat, and exacerbating issues such as food spoilage and water loss due to non-functional water pumps. Australia, at the same time, has the benefit of significant solar resources. Although dense smoke can limit photovoltaic (PV) output, this places Australia in a good position to utilize distributed solar energy resources, especially in areas that may have more sparse access to the grid or be particularly vulnerable to bushfires.

The Victoria towns of Donald and Tarnagulla also provide remarkable examples of microgrid deployment. As these towns are at high risk of being cut off from grid supply in the case of bushfire (as well as other extreme weather events such as flooding), a feasibility study is considering the development of a DER-based microgrid that could exploit PV, battery storage, diesel generators, and intelligent control of various non-essential loads enabled by smart meters. To assess the resilience value potentially brought by the microgrid, as well as design the optimal local DER portfolio in conjunction with potential network augmentation, a risk-based probabilistic techno-economic framework is being adopted. Part of the challenge is to step out of specific sandbox setups and allow the adoption of this kind of advanced planning methodologies as regulatory business as usual.

Others

The deployment of microgrids is becoming an attractive solution against wildfires and extreme events around the globe. In Canada, there are various incentive programs (e.g., the Green Municipal Fund by the Federation of Canadian Municipalities) across the provinces to encourage communities to invest in sustainable, renewable-based microgrids. This includes both grid-connected and off-grid installations in indigenous communities which face serious challenges with secure electricity supply during extreme events.

Hawaii Electric Light Company promotes microgrid development to protect remote communities that might isolate from the grid in the face of severe events on the island, such as fires, volcano eruptions, and hurricanes.

Following the 2011 Great East Japan earthquake and tsunami, Japan accelerated its microgrid program. Microgrids were promoted for schools, industrial facilities, and emergency services, and a notable community system was installed at Higashi Matsushima.

These real-world examples and initiatives illustrate both the opportunities and challenges associated with using DERs and microgrids for resilience. The increasing realization that this is becoming the "new norm" as a direct impact of climate change, with longer heat and drought periods, has pushed key stakeholders and decision-making bodies to take the issue more seriously than ever before.

The following sections provide a systematic discussion on the role and beneficial utilization of DERs exploited through microgrids under the wildfire threat and how DER investments can be planned to effectively complement network investments against wildfires.

Utilization of DERs under wildfire threat

In case of a progressing wildfire, the DERs of an endangered power system and mobile power sources can be utilized to minimize load shedding due to wildfire impact on system components. For instance, the schedule of flexible loads and placement of mobile energy resources can be determined considering the system components affected by the wildfire and when they are expected to be affected. This section presents actions that can be taken by a system operator to mitigate the impact of a progressing wildfire on the electrical system and minimize customer interruptions.

To detect a wildfire and estimate its scale and progression, a situational awareness system is necessary. The information from such a system can help assess the spatiotemporal impact on each system component. An effective assessment of the affected components is useful not only for determining the emergency operational response, but also for the restoration phase as it allows the system operator to develop an efficient restoration strategy.

Before the event, camera networks, combined with machine learning techniques for image analysis, can automatically detect a wildfire outbreak. Once a wildfire is detected or reported, its propagation can be assessed. Using the spatial data of an endangered system, e.g., by a geographic information system (GIS), the distance between the wildfire and the conductors or transformers can be estimated during the wildfire's progression. Based on that estimate, the wildfire's impact on them can be assessed. For instance, the temperature of any line can be estimated. Therefore, its status can be evaluated to determine the operation of system assets to minimize the approaching wildfire's impact. If part of the system is expected to be isolated due to line-related damage, the operator prepares for its smooth operation and the uninterrupted supply for consumers by forming self-sufficient microgrids whenever possible.

Wildfires spread depending on various factors, including weather parameters (e.g., wind speed and direction and relative humidity), the vegetation of the crossing area, terrain slope, fuel bed conditions, and flame front properties. Hence, weather forecasting tools and systems (e.g., satellite observations) for acquiring knowledge of territory characteristics are vital. Wildfire tracking is also important as collected data during wildfire progression can be used to update propagation assessment and organize system emergency responses. Satellites and unmanned aerial vehicles can be used to monitor wildfire progression when approaching the fire is unsafe.

There are a variety of tools available to estimate wildfire propagation. PG&E uses a tool developed by Technosylva to derive fire propagation and consequence outcomes, such as impacted infrastructure. Additionally, the U.S. Forest Service uses the FlamMap application which includes the FARSITE simulator to compute wildfire growth and behavior. The tool considers detailed sequences of weather conditions. Since propagation depends on weather forecasting and terrain characteristics that cannot be quantified with great accuracy, different scenarios can be explored by considering the forecast error and quantification accuracy of terrain characteristics. PG&E highlighted the need to use a probabilistic fire spread model.

Once the timing and impact of wildfire on system components is assessed, a preemptive operation strategy can be determined. Customer interruptions may be mitigated through the schedule and dispatch of the DERs and network reconfiguration, taking into account the stochastic generation of renewables. Wildfires mainly affect overhead lines, poles, and substations components. Concerning overhead lines, a wildfire can damage them or erode their thermal rating due to the increase of the conductor's surface temperature. Also, the impact of wildfire on DERs can be estimated to develop a strategy based on the available generation units. DERs can be fully destroyed by the wildfire or their operation can be affected by its smoke. For instance, wildfire smoke contains small particles that reduce the amount of sunlight reaching solar panels, reducing the PV output.

To mitigate issues expected from a reduction in a conductor's safe carrying capacity, the system can be reconfigured with DERs and other resources operated to avoid limit violation and tripping. If line damage is expected, the system operator needs to determine a system reconfiguration to maintain the full connectivity of the system. If full connectivity is not possible, appropriate schedule and dispatch of the DERs may minimize load shedding in the isolated parts of the system and ensure uninterruptible system operation. If the wildfire damages a substation, load shedding of downstream loads can be mitigated by using the residential DERs (including flexible loads) connected to the low voltage distribution system.

Figure 5 shows damage provoked by the 2007 forest fires in Greece. In the case of Greece wildfires, monitoring the spatiotemporal impact of the wildfires via GIS has assisted the distribution system operator in choosing appropriate locations for the mobile generators to reduce restoration times after the damage. GIS information also enables the rapid development of restoration plans. The timely estimation of the required number of repair crews and necessary materials for system restoration significantly shortens system restoration times. A tool for estimating wildfire propagation was not available in Greece. Such a tool could support faster decisions to identify which buses to connect the mobile generators, further reducing customer interruptions.

Figure 5: Damaged lines and poles from the 2007 forest fires in Greece (Courtesy: Public Power Corporation, Greece).

If a situational awareness system is unavailable, and therefore, propagation of the wildfire and its impact on system components cannot be assessed, DERs can be scheduled and dispatched to form smaller self-adequate microgrids. In this way, when a line is set offline due to the wildfire, the downstream system can survive with minimum load shedding as it is already organized as a self-adequate microgrid able to meet the demand individually. However, the system reconfiguration, schedule of the flexible loads, state of charge of the energy storage system, and the placement of mobile energy resources cannot be determined optimally without the information provided by a situational awareness system.

In addition to preventive actions, proper corrective actions are necessary to mitigate the impact on the system during the restoration phase. Once the wildfire has been extinguished and the damaged components have been identified, the development of a restoration plan, including the damage repair sequence, network reconfiguration, and utilization of DERs, is highly important. The order of repairs can be based on the capability of DERs to meet demand in the isolated areas of the system. For instance, if the DERs within an isolated area can meet the demand for a long period, the damages that led to the isolation of this area can be repaired last. Also, the routing of mobile resources can be coordinated with the repair sequence. Mobile resources can be used to mitigate the load shedding of the isolated areas until the damaged components are restored. In this case, the status of the transportation network is also taken into account to determine the routing of mobile resources.

Planning DER investments against wildfires

Most parts of the electrical network were built decades ago, and, in many cases, without considering natural threats such as wildfires. Today, several critical network infrastructures and supply/entry points to distribution networks are highly exposed to natural hazards. The severe impact of wildfires on the electricity supply demonstrates the need to prepare against such future events.

A well-established body of recent work has been dedicated to calculating the probability of large wildfires. The Keetch-Byram Drought Index, the Fire Potential Index, and the Large Fire Probability, which have been widely used in the United States, are good examples of metrics to identify areas with wildfire potential. In another example, shown in Figure 6, the Chilean forest authority uses the Forest Fire Ignition Probability Map for the same purpose. This probability is computed daily based on solar radiation, temperature, and dead fine-fuel moisture.

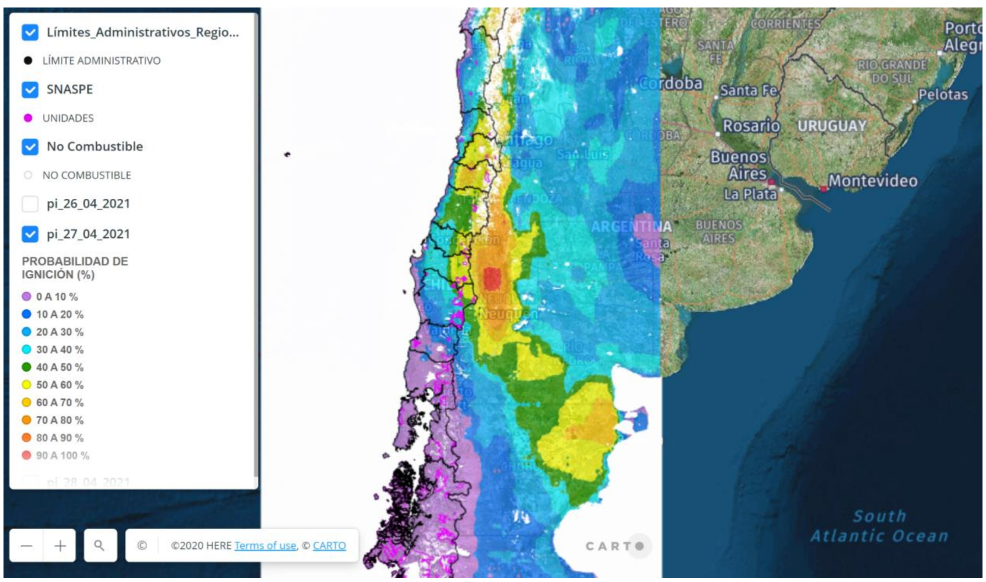

Figure 6: Forest Fire Ignition Probability Map (April 27, 2021).

Source: https://geprif.carto.com/

Apart from these probabilities, historical data is available regarding the duration of large wildfire events and repair times of the faulted electrical infrastructure after such catastrophic events. Also, from recent experiences in Chile, the power network may be impacted in several points simultaneously by a large wildfire event (Figure 7). Under these conditions with lost supply points from the main grid, an optimal DER portfolio could be used to supply the internal loads.

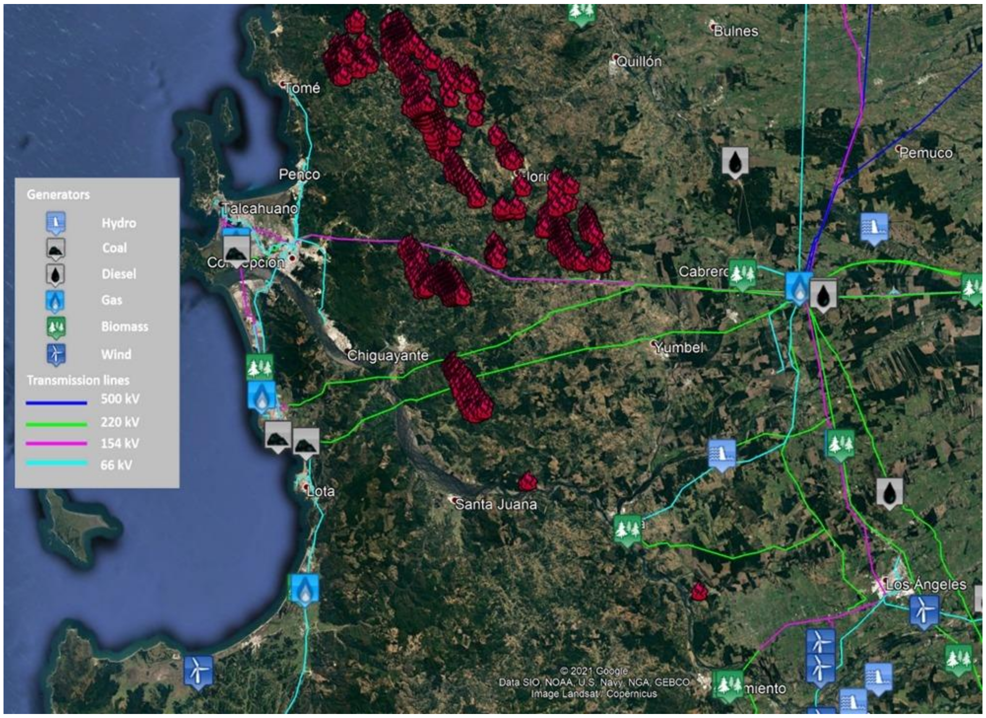

Figure 7: Representation of wildfires in Chile on Jan. 26, 2017.

Planning an optimal DER portfolio against large wildfires requires a suitable methodology that considers several relevant uncertainties. The following presents a proposed methodology for resilient network design, used in the "Review of Distribution Network Security Standards" and now under development in the United Kingdom. A similar risk-based probabilistic techno-economic framework is being used to inform policymakers and industry in Chile and Australia.

A suitable methodology to design DER portfolios against wildfires

The following methodology seeks optimal investments in DER portfolios to efficiently hedge a distribution system against high-impact low-probability events such as wildfires. The methodology is based on an optimization model and, importantly, also allows capturing the substitution effect between DER and network investments since it co-optimizes both. In operational timescales, the model determines the optimal operation of the distribution system with DERs, including purchases from the main grid and topology control. Hence, the optimization model can identify optimal preventive and corrective measures to hedge the distribution system against potential outage scenarios originated from wildfires. The model optimizes the following set of decisions:

- **Preventive measures:** Investments in DER equipment such as storage plants, backup generation, and network investments. The model also finds the optimal volume of demand response contracted. These measures are made upfront, pre-contingency, and thus are present in all scenarios.
- **Corrective measures:** These measures depend on the specific contingency and are scenario dependent. We model two types of corrective measures, fast and slow:
    - **Fast:** Refers to the distribution system operation itself, including demand curtailments and a (smart) operation of system assets (topology control and dispatchable DER). These actions can occur right after a contingency occurs.
    - **Slow:** Installing and dispatching mobile DER. These actions feature a lag associated with the arrival of mobile equipment.

The proposed optimization model is probabilistic, minimizing expected costs (including the cost of investment, operation, and energy not supplied, and, eventually, a risk metric to capture risk aversion). It also considers the occurrence of several scenarios (each with a probability) in the form of a comprehensive set of system outages, including those triggered by wildfires. Importantly, in the event of a wildfire, the probability of simultaneous outages becomes high since a single fire event can affect various pieces of system equipment. Here, ignition probability maps as those in Figure 6 (and other risk indices associated with wildfires discussed earlier) can inform about the places with the highest risks of wildfires.

Illustrative case study example

The model above was applied to the textbook-like system design example displayed in Figure 8. This example was used in the "Review of Distribution Network Security Standards" in the United Kingdom to illustrate, from a fundamental viewpoint, the problems of the current network standards and the potential solutions going forward. This example seeks to determine, in a greenfield fashion, the optimal system design to supply areas A and B. The figure shows all candidate assets (i.e., investment propositions) to supply the constant loads in the two distribution networks (25 MW in Area A and 50 MW in Area B). The set of candidate assets includes six power lines and distributed PV and battery systems in Area A. In case of network outages, the choices of renting mobile generation units and exercising DR contracts in Area A and B as corrective actions could also be considered as part of the system design. Importantly, the failure rates of lines 5 and 6 are affected by the risk of wildfires, which increases the probabilities of failures in that network corridor and originates dependencies of line failure probabilities between lines 5 and 6.

Under normal conditions, the outage rate of lines is 1 occurrence per year (occ/yr) with a mean time to repair of one day. Under catastrophic wildfire conditions in the neighboring area of lines 5 and 6 (1 occurrence in 10 years), we assume these lines will fail (simultaneously) and that their mean time to repair increases to 30 days. Other relevant input data include an energy price of $50/MWh (use to buy energy from the main grid), a value of lost load (VoLL) equal to $10,000/MWh, and the investment costs of lines, PV, and storage of $75/MW.km.yr, $500/kW, and $200/kWh, respectively.

Regarding the mobile generation units in both areas, the system operator can rent them at an hourly cost of $68.5/MW and operate them with a $200/MWh fuel cost. For simplicity, DR features the same costs as those of mobile units. We also assume that the system operator takes an average of 2.4 hours and three days, respectively, to install the mobile units under normal and wildfire conditions. Mobile units and DR measures can cope with up to half the power demand in each area.

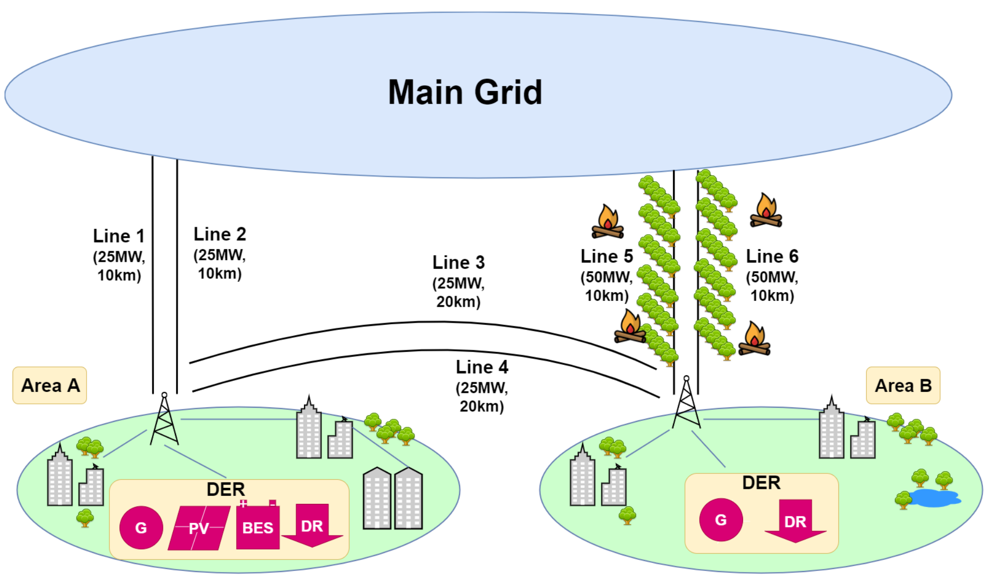

Figure 8}: Electricity network and DER candidates along with areas exposed to wildfires.

We consider 22 scenarios, including one intact system (with no outages), six N-1 line outages, and 15 N-2 line outages. The probabilities of these scenarios are calculated assuming independence and dependence under normal and wildfire conditions, respectively. Hence, once a wildfire occurs (every

10 years on average), a common mode failure arises, affecting lines 5 and 6 simultaneously. The probabilities with and without the risk of wildfires are shown in Table 1. Notably, the probability of a double contingency affecting lines 5 and 6 increases by more than 110,000% when we assume a wildfire every 10 years (on average).

Table 1: Scenario probabilities without and with the risk of wildfires. Dependent probabilities have been marginalized (using the fraction of the time to which the network is exposed to a wildfire).

	Probabilities		
	Independent	**Dependent**	**Variation**
Intact system	9.84E-01	9.76E-01	-1%
All N-1 failures	1.62E-02	1.60E-02	-1%
All N-2 failures but L5-6	1.03E-04	1.03E-04	-1%
Double failure of L5-6	7.38E-06	8.16E-03	110404%
All failures beyond N-2	4.05E-07	4.02E-07	-1%

Note that knowing the actual probability distribution functions of rare events such as wildfires may be difficult. Nevertheless, the probabilistic framework may still be beneficial for deriving good estimates when certain probability values are assumed. Alternatively, other optimization frameworks (not referenced here) that do not rely on probability values may be promising for resilience analysis.

Table 2 shows the results found for three cases, namely, Case A, Case A Re-evaluated, and Case B. Case A corresponds to the results when the risk of wildfires in the neighboring area of lines 5 and 6 is neglected (i.e., independent probabilities used in the optimization). Case A Re-evaluated features the same infrastructure as Case A, where the costs of operation and unserved energy have been re-evaluated, including the risk of wildfires (i.e., independent probabilities used in the optimization and dependent probabilities used in the re-evaluation). Case B corresponds to the optimal design when the risk of wildfires is appropriately considered (i.e., dependent rather than independent probabilities have been considered in the optimization).

Table 2: Results with costs in thousand dollars (k$) per year. L, MG, DR, PV, and BES refer to line, mobile generator, demand response, PV panels, and battery energy storage, respectively.

	Case A	Case A (Re-evaluated)	Case B
Assets and measures	L1, L2, L5, L6, MG, DR	L1, L2, L5, L6, MG, DR	L1, L2, L3, L4, L5, PV, BES, MG, DR
PV+BES investment cost	-	-	11,500
Line investment cost	113	113	150
Operational cost	32,850	33,115	21,901
Lost load cost	27	19,665	6
Total cost	32,990	52,893	33,558

The Classic N-1 design

Suppose we neglect the risk of wildfires in the neighboring area of lines 5 and 6. In that case, the optimal system design found by the probabilistic model will be the classic N-1 configuration, installing lines 1 and 2 (25 MW each) and lines 5 and 6 (50 MW each) without installing up-front DER capacity (Case A in Table 2). Interestingly, mobile generators and DR in both areas can be used as corrective actions to mitigate the impacts of N-2 line outages and thus supply part of the load.

The resilient design

Suppose we consider the risk of wildfires in the area in question. In that case, the optimal system design will include a richer set of DERs, combining up-front investments in PVs and battery systems with corrective actions in the form of mobile generating units and DR (Case B in Table 2). Remarkably, the consideration of this richer set of DERs will reduce line investments through the risky network corridor (investment in line 6 is dropped) and increase investments in lines to transfer power between areas A and B (lines 3 and 4). This resilient design solution will limit the lost-load cost to only $6,000 per year (which is significantly smaller than the lost-load cost of the other solutions), including the unserved demand during wildfires. Another remarkable result is that the PVs and battery systems, triggered by increasing the risk of wildfire from no occurrence to 1 occurrence in 10 years, are also used to reduce the power imported from the main grid under normal conditions, decreasing operational costs. These results demonstrate the multiple benefits of DERs and the importance of capturing these in the cost-benefit analysis to justify investments.

The actual risks associated with the current security standards

Table 2 conveys another lesson. The actual risk to which the system is exposed due to applying the current security standards is significant. Indeed, the expected unsupplied energy cost of Case A RE-evaluated is 700 times higher than the initial evaluation (see differences between Case A and Case A Re-evaluated), increasing the total cost of the system design to almost twice the first estimate. Instead, suppose wildfire risks were appropriately recognized from the beginning to plan the system accordingly (as in Case B). In that case, the increases in total costs of the resilient design will be almost negligible compared with the initial cost estimations of the classical N-1 design (see differences in total costs between Case A and Case B). This result demonstrates the importance of appropriate resilient planning.

The way forward

Smart grid resilience

The conventional electricity network is getting smarter, meaning that:

1. Generation, storage systems, and other energy resources will become increasingly distributed, as load control inherently is located closer to or at the demand points, (e.g., rooftop PV arrays).
2. Networks will employ more modern technology and become more active through new flexible systems (e.g., flexible alternating current transmission systems, HVDC, and other power electronic-based equipment, such as grid forming inverters). Also new monitoring, control, protection, information, and communication technologies will be deployed.
3. Demand will become more controllable, with consumers participating actively in market and system operations.

In this vein, transport and heating/cooling electrification will present prospects to capitalize on flexible and controllable loads, exploiting their virtual storage capabilities. In the future smart grid world, the digitalization of energy systems will provide unique opportunities for much smarter management of the electricity system during extreme events. For instance, this smart management can include switching off non-essential demand when the network is stressed while supplying essential demand. The supply of essential loads during emergencies will also be enabled by DERs and virtual storage capabilities from demand (e.g., battery units from electric vehicles). This would significantly enhance the resilience of supply delivered as energy consumers will have their essential load supplied during high-impact events, including wildfires and other natural catastrophes.

<u>New regulatory arrangements for a resilience future</u>

Private, competitive agents could efficiently undertake investments in distributed generation and other DERs in a decentralized fashion if the market appropriately remunerated investors. Hence, a distributed energy resource enhancing resilience could be remunerated, for instance, in terms of the (marginal) benefits originated by the lost-load cost savings caused by its presence. Fostering resilience through pure market signals, though, may encounter practical problems as follows:

- The distribution network investment regime may not be compatible with the efficient deployment of DERs. Indeed, DERs may even compete against new network infrastructure (usually built in a regulated, mandated fashion) for services such as reliability and resilience. Hence, some form of coordination may be needed, promoting the right share of investments between wires and non-wires (DERs) solutions
- Prices in distribution networks do not reflect the actual locational marginal cost of energy, including those during scarcity conditions. In fact, for appropriate market-driven investments in DERs, prices in distribution networks during scarcity conditions (right after a threat occurs) should be equal to the VoLL precisely in those areas/feeders where demands are being curtailed. Given the extreme social conditions associated with natural hazards such as wildfires, it may be politically impractical to maintain prices equal to the VoLL under such circumstances
- Even if efficient pricing were in place for distribution networks, concerns remain regarding the performance of market-driven investments:
    - Probability distribution functions of rare events such as wildfires are unknown and non-stationary due to climate change. Hence, a DER portfolio meant to hedge these risks would be difficult to justify on a market-driven basis.
    - The above problem is exacerbated by the risk aversion of self-interest investors, who require more confidence about the revenue streams associated with their investments.
    - Also, investors may act strategically to not fully provide a robust system design, preserving high prices in times of scarcity conditions.

These points suggest that pure markets will generally not deliver resilient DER solutions, and hence standards or mandates will be needed. However, part of the underlying problems associated with natural hazards, such as wildfires, remain in the centralized solution. A more centralized system planning problem will still need a definition of appropriate risk aversion levels and assumptions on partially unknown probabilities. This will require careful attention and, indeed, further research, mathematical models (particularly, optimization models under uncertainty), planning, and regulation going forward. In this vein, our previous examples and analyses can inform the development of future standards for resilience as in the United Kingdom, Chile, and Australia.

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Further reading

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- Nikos Hatziargyriou is with the ex-chairman and CEO of Hellenic Distribution Network Operator (HEDNO).

Workpaper Title:

Remote Grid Workpaper

WP SCE-04 Vol. 05 Part 3

SOUTHERN CALIFORNIA EDISON An EDISON INTERNATIONAL℠ Company	SOUTHERN CALIFORNIA EDISON			
	Wildfire Mitigation Strategy			
Remote Grid	Prepared by:	[redacted]	Date:	2/21/2023
	Reviewed by:		Date:	
	Approved by:		Date:	

Remote Grid Working Paper

Remote grid (RG) is a small power system isolated from the main grid that includes generation resources to supply remote and small collection of customers. RGs utilizes distributed energy resources (DERs) that consist of small power generating and/or storing systems like PV, batteries, and wind turbines that supply power to the loads.

Consider a remote community that is fed by a long power line trespassing an area with high wildfire risk, as shown in Figure 1. Undergrounding the power line (the dashed line in the figure) is one way to eliminate the ignition risk. However, if undergrounding of distribution power lines are infeasible, remote grid may be a viable alternative solution to avoid the ignition risk. For instance, by deenergizing the power line in Figure 1 and forming a remote grid including the DERs and loads, the risk of wildfire due to the power line is eliminated.

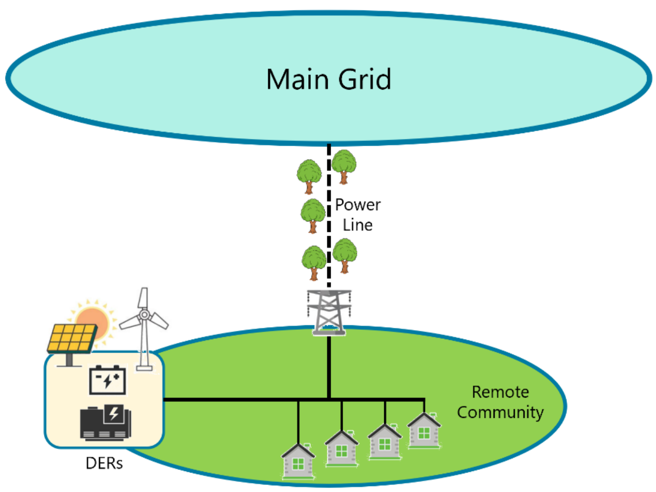


Figure 1. Conceptual Diagram of a Remote Grid

Feasibility study is the first step to evaluate the potential of RG as an alternative option for undergrounding. The number of studies were determined based on SCE's evaluation of locations where undergrounding is infeasible and load appears to be relatively small. This list was further refined using SCE's IWMS risk tranches to prioritize locations in Severe Risk Areas. From this review process, SCE has identified 13 locations that meet the criteria, as listed in Table 1. More details for each site is provided in Appendix A. These sites are mostly composed of small pockets of load fed by long lines.

Table 1. Remote Grid Candidates

RG ID	Circuit	District	Region	Reason	Average Load (kVA)	Maximum Load (kVA)

SOUTHERN CALIFORNIA EDISON An EDISON INTERNATIONAL Company	SOUTHERN CALIFORNIA EDISON				
	Wildfire Mitigation Strategy				
Remote Grid		Prepared by:	[redacted]	Date:	2/21/2023
		Reviewed by:		Date:	
		Approved by:		Date:	

RG1	CARMELITA	CARMELITA	Desert	Difficult terrain for undergrounding	2.78	30.20
RG2	ACOSTA	ACOSTA	Desert	Difficult terrain for undergrounding	29.86	59.20
RG3	HUCKLEBERRY	HUCKLEBERRY	North Coast	Long line for a very small number of customers	18.53	83.10
RG4	AVENIDA	AVENIDA	Metro East	Difficult terrain for undergrounding	2.31	11.91
RG5	ONBORD	ONBORD	Metro East	Difficult terrain for undergrounding	72.87	145.75
RG6	AGNEW	AGNEW	Rurals	Difficult undergrounding through a rock canyon	-	-
RG7	HESSION	HESSION	Rurals	Long line for a very small number of customers	-	-
RG8A	BRYDON	BRYDON	Metro East	Undergrounding requires extensive re-routing with some difficult terrain	18.46	87.57
RG8B	BRYDON	BRYDON	Metro East	Undergrounding requires extensive re-routing with some difficult terrain	18.51	45.60
RG9	FANO	FANO	Metro East	Difficult terrain for undergrounding	7.82	54.10
RG10	BROADCAST	BROADCAST	Metro East	Difficult terrain for undergrounding	-	-
RG11	TUFA	TUFA	Rurals	Long line for a very small number of customers	20.63	160.24
RG12	MT. GIVENS	Shaver Lake	San Joaquin	Long line for a very small number of customers	8.81	26.31
RG13	BIRCHIM	Bishop/Mammoth	Rurals	Long line for a very small number of customers	5.49	32.43

SCE plans to employ consultant(s) to conduct feasibility studies for each potential location, 4 in 2023, 4 in 2024, and 5 in 2025. Table 2 lists the cost associated with feasibility studies.

Table 2. Remote Grid Feasibility Studies Cost Projection

	2023	2024	2025
Number of Locations for Feasibility Studies	4	4	5
O&M – Feasibility Studies	$120 k	$120 k	$150 k

SOUTHERN CALIFORNIA EDISON An EDISON INTERNATIONAL™ Company	SOUTHERN CALIFORNIA EDISON			
	Wildfire Mitigation Strategy			
Remote Grid	Prepared by:	[redacted]	Date:	2/21/2023
	Reviewed by:		Date:	
	Approved by:		Date:	

DOH at 8%	$10 k	$10 k	$12 k

The cost associated for each feasibility is estimated at $30,000, which was provided by vendors. Please refer to Remote Grid Workpaper Addendum for a breakdown of forecasted costs associated with this activity. Table 3 presents the tasks and their percentages of the overall cost estimate for each feasibility study.

Table 3. Remote Grid Feasibility Study Cost Breakdown

Task	Outcome	Cost Percentage
Site Visit	Civil construction requirements	15 %
Historic Load Analysis	Size and type of resources required for the remote grid	15 %
Review of Land Ownership and Jurisdiction Authority	Location of remote grid resources, communication and control equipment	10 %
Cost Analysis of Deployment of Remote Grid	Full cost proposal and schedule for deployment of the remote grid	60 %

If the feasibility study concludes that remote grid is feasible and cost-effective, remote grid will be determined as the alternative hardening approach. If the study finds that remote grid installation is not feasible due to construction, vegetation, cost, or other challenges, SCE may consider deploying covered conductor or any additional mitigations such as inspections and vegetation management.

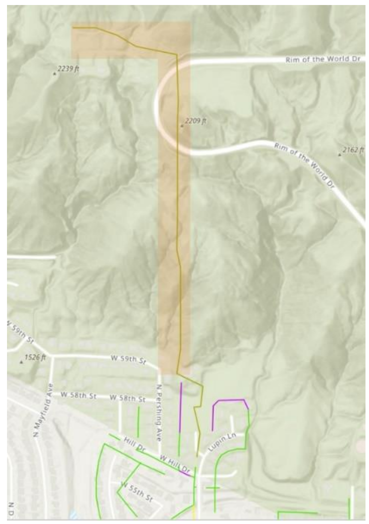
SOUTHERN CALIFORNIA EDISON An EDISON INTERNATIONAL Company	SOUTHERN CALIFORNIA EDISON				
	Wildfire Mitigation Strategy				
Remote Grid	Prepared by:	[redacted]	Date:	2/21/2023
	Reviewed by:		Date:	
	Approved by:		Date:	

Appendix A

RG1

Challenges for undergrounding the highlighted section are:

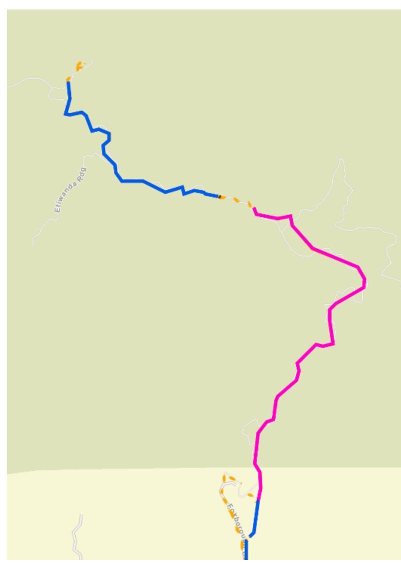
- Difficult terrain for undergrounding
- Street side poles



RG2

Challenges for undergrounding the section shown in blue are:

- Difficult terrain for undergrounding
- High environmental concerns



SOUTHERN CALIFORNIA EDISON An EDISON INTERNATIONAL Company	SOUTHERN CALIFORNIA EDISON			
	Wildfire Mitigation Strategy			
Remote Grid	Prepared by:	[redacted]	Date:	2/21/2023
	Reviewed by:		Date:	
	Approved by:		Date:	

RG3

Challenges for undergrounding the section shown in purple are:

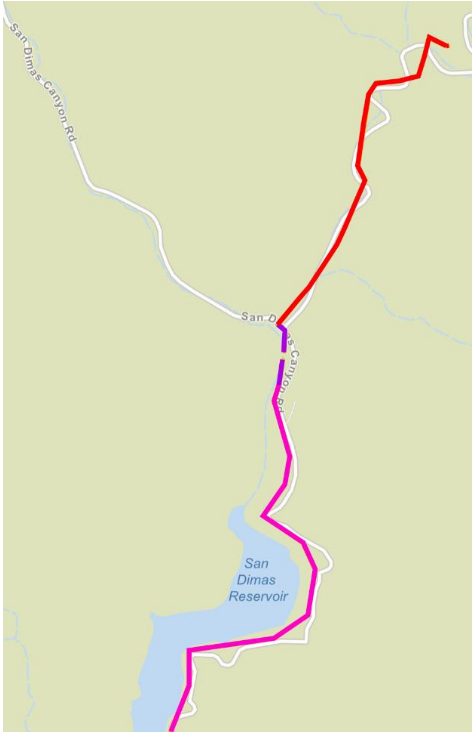
- Very long section for a small number of load (high cost)

SOUTHERN CALIFORNIA EDISON An EDISON INTERNATIONAL Company	SOUTHERN CALIFORNIA EDISON				
	Wildfire Mitigation Strategy				
Remote Grid		Prepared by:	[redacted]	Date:	2/21/2023
		Reviewed by:		Date:	
		Approved by:		Date:	

RG4

Challenges for undergrounding the section shown in purple are:

- Difficult terrain for undergrounding



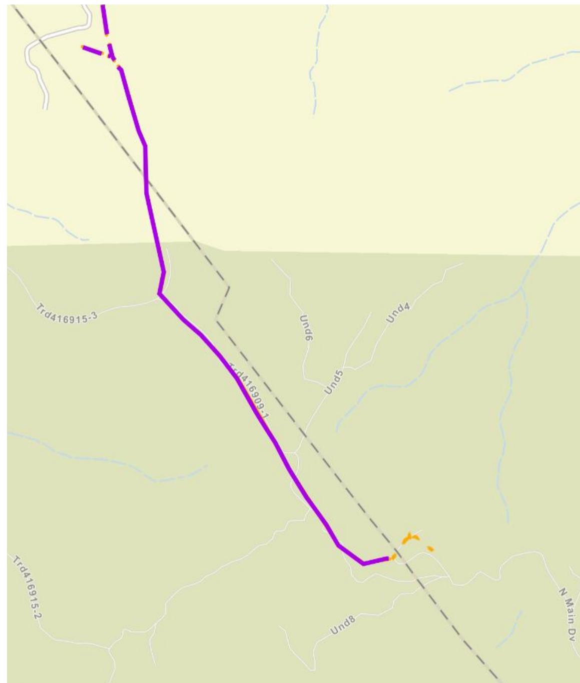
6

SOUTHERN CALIFORNIA EDISON An EDISON INTERNATIONAL Company	SOUTHERN CALIFORNIA EDISON				
	Wildfire Mitigation Strategy				
Remote Grid	Prepared by:	[redacted]	Date:	2/21/2023	
	Reviewed by:		Date:		
	Approved by:		Date:		

RG5

Challenges for undergrounding the section shown in purple are:

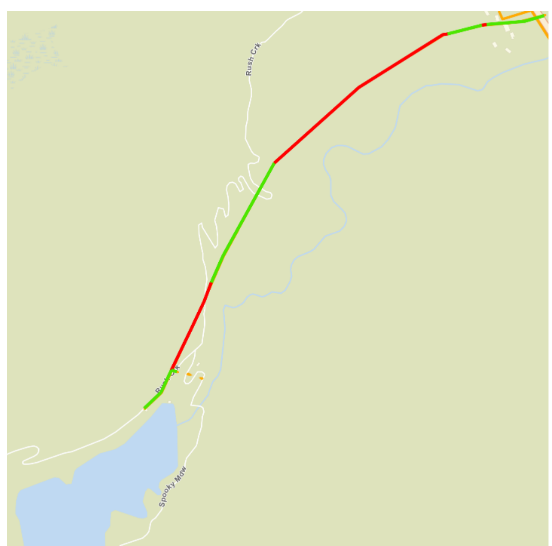
- Difficult terrain for undergrounding



RG6

Challenges for undergrounding the section shown in green and red are:

- Difficult terrain for undergrounding (lines cut through a rock canyon)



SOUTHERN CALIFORNIA EDISON An EDISON INTERNATIONAL™ Company	SOUTHERN CALIFORNIA EDISON			
	Wildfire Mitigation Strategy			
Remote Grid	Prepared by:	[redacted]	Date:	2/21/2023
	Reviewed by:		Date:	
	Approved by:		Date:	

RG7

Challenges for undergrounding the section shown in purple are:

Difficult terrain for undergrounding

- Very long section for a small number of load (high cost)

RG8

Challenges for undergrounding the section shown in purple are:

- Very long section for a small number of load (high cost)
- Difficult terrain for undergrounding

	SOUTHERN CALIFORNIA EDISON			
	Wildfire Mitigation Strategy			
Remote Grid	Prepared by:	[redacted]	Date:	2/21/2023
	Reviewed by:		Date:	
	Approved by:		Date:	

RG9

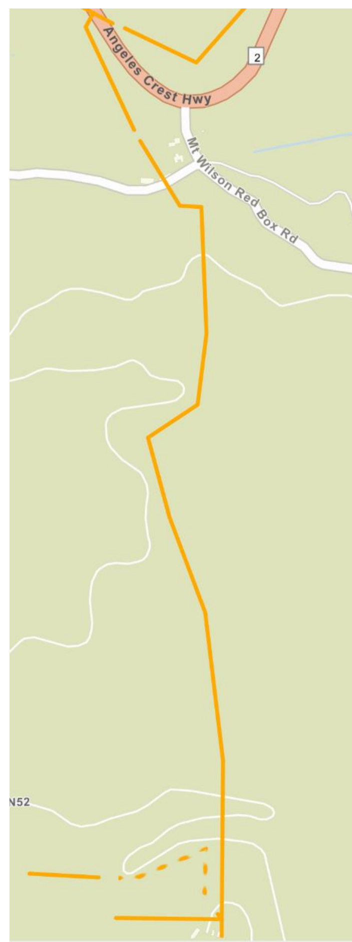
Challenges for undergrounding the section shown in purple are:

- Long section for a small number of load (high cost

RG10

Challenges for undergrounding the section shown in orange are:

- Difficult terrain for undergrounding (narrow and steep load)
- Undergrounding project would most likely have long delays as this is the only route through this area and Cal Trans Jurisdiction.

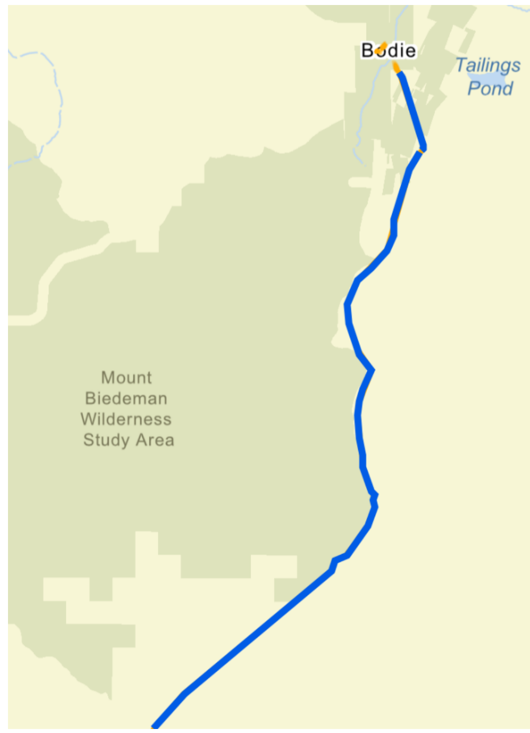


SOUTHERN CALIFORNIA EDISON				
Wildfire Mitigation Strategy				
Remote Grid	Prepared by:	[redacted]	Date:	2/21/2023
	Reviewed by:		Date:	
	Approved by:		Date:	

RG11

Challenges for undergrounding the section shown in blue are:

- Very long section for a small number of load (high cost)



RG12

Challenges for undergrounding the section shown in green and red are:

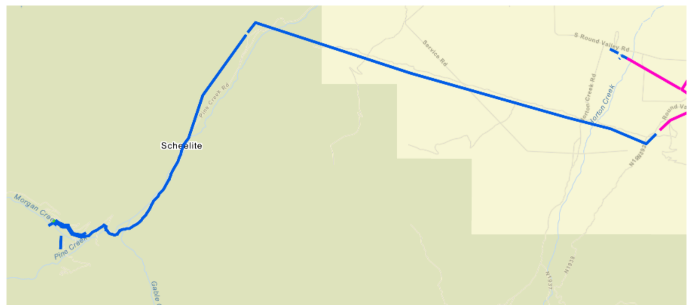
- Very long section for a small number of load (high cost)

SOUTHERN CALIFORNIA EDISON An EDISON INTERNATIONAL℠ Company	SOUTHERN CALIFORNIA EDISON			
	Wildfire Mitigation Strategy			
Remote Grid	Prepared by:	[redacted]	Date:	2/21/2023
	Reviewed by:		Date:	
	Approved by:		Date:	

RG13

Challenges for undergrounding the section shown in blue are:

- Very long section for a small number of load (high cost)
- Difficult terrain for undergrounding



Workpaper Title:

O&M Detail for Alternative Technologies

WP SCE-04 Vol. 05 Part 3

SOUTHERN CALIFORNIA EDISON®

An EDISON INTERNATIONAL® Company

(U 338-E)

2025 General Rate Case

A. 23-05-

Workpapers

SCE-04 Resiliency
Volume 5 Pt. 3 - Wildfire Management
Alternative Technologies

May 2023

2025 GRC Summary

(Constant 2022 $000)

Beginning of Workpapers for:	
Exhibit:	SCE-04 Resiliency
Volume:	5 Pt. 3 - Wildfire Management
Business Planning Element:	Wildfire Management
Activity:	Alternative Technologies
Witness:	A.Swisher/R.Fugere

Cost Type	Recorded/Adj. 2022	Forecast 2025
Labor	618	329
Non-Labor	636	614
Other	0	0
Total	**1,254**	**942**

Due to rounding, totals may not tie to individual items.

Description of Activity:
This activity includes costs associated with several emerging technologies including studies and pilots, e.g., EFD and DOPD

Forecast Methods - Summary of Results of Methods Studied

(Constant 2022 $000)

Exhibit:	SCE-04 Resiliency
Volume:	5 Pt. 3 - Wildfire Management
Business Planning Element:	Wildfire Management
Activity:	Alternative Technologies
Witness:	A.Swisher/R.Fugere

Cost Type	Recorded/Adj.				
	2018	2019	2020	2021	2022
Labor	0	0	121	564	618
Non-Labor	0	0	13	450	636
Other	0	0	0	0	0
Total	**0**	**0**	**135**	**1,013**	**1,254**

Cost Type	Results of Linear Trending					
	3 Years: 2020 - 2022		4 Years: 2019 - 2022		5 Years: 2018 - 2022	
	$	r2*	$	r2*	$	r2*
Labor	1,428	0.83	1,359	0.91	1,160	0.86
Non-Labor	1,612	0.95	1,330	0.90	1,081	0.81
Other	0	0.00	0	0.00	0	0.00
Total	**3,040**	**N/A**	**2,689**	**N/A**	**2,241**	**N/A**

Cost Type	Results of Averaging							
	2 Years:		3 Years:		4 Years:		5 Years:	
	2021 - 2022	sd**	2020 - 2022	sd**	2019 - 2022	sd**	2018 - 2022	sd**
Labor	591	27	434	222	326	269	261	274
Non-Labor	543	93	366	261	275	276	220	270
Other	0	0	0	0	0	0	0	0
Total	**1,134**	**N/A**	**801**	**N/A**	**601**	**N/A**	**480**	**N/A**

Cost Type	Last Recorded Year		
	2023	2024	2025
Labor	618	618	618
Non-Labor	636	636	636
Other	0	0	0
Total	**1,254**	**1,254**	**1,254**

Cost Type	Itemized Forecast		
	2023	2024	2025
Labor	1,764	403	329
Non-Labor	757	668	614
Other	0	0	0
Total	**2,522**	**1,071**	**942**

** r2 = R Squared (Based on recorded years data)*

*** sd = standard deviation (Based on recorded years data)*

2025 GRC Selected Forecast Method

(Constant 2022 $000)

Exhibit:	SCE-04 Resiliency
Volume:	5 Pt. 3 - Wildfire Management
Business Planning Element:	Wildfire Management
Activity:	Alternative Technologies
Witness:	A.Swisher/R.Fugere

Cost Type	Recorded/Adj.					Forecast			Selected Forecast		TY Forecast Incr/(Decr) from 2022
	2018	2019	2020	2021	2022	2023	2024	2025	Method	($000)	
Labor			121	564	618	1,764	403	329	Itemized	329	(289)
Non-Labor			13	450	636	757	668	614	Itemized	614	(23)
Other											
Total	**0**	**0**	**135**	**1,013**	**1,254**	**2,522**	**1,071**	**942**		**942**	**(312)**

Due to rounding, totals may not tie to individual items.

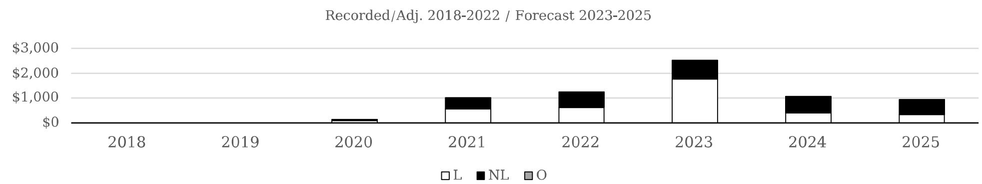
Analysis of Forecasting Methods
Itemized Forecast: Itemized Forecast Method

Other Forecast Methods not Selected
Last Recorded Year: In D.89-12-057, and subsequently in D.04-07-022, the CPUC stated that if recorded expenses have been relatively stable for three or more years, the last recorded year is an appropriate base estimate. For this activity the Last Recorded Year method does not account for the variables discussed in testimony to determine the 2025 Test Year forecast. Therefore, the Last Recorded Year method is not appropriate.
Linear Trending: In D.89-12-057, and subsequently in D.04-07-022, the CPUC stated that if recorded expenses have been relatively stable for three or more years, the last recorded year is an appropriate base estimate. For this activity the Linear Trending method does not account for the variables discussed in testimony to determine the 2025 Test Year forecast. Therefore, the Linear Trending method is not appropriate.
Averaging: In D.89-12-057, and subsequently in D.04-07-022, the CPUC stated that if recorded expenses have significant fluctuations from year to year, or expenses are influenced by external forces beyond the utility's control, an average of recorded-expenses is appropriate. For this activity the Averaging method does not account for the variables discussed in testimony to determine the 2025 Test Year forecast. Therefore, the Averaging method is not appropriate.

2025 GRC Year Over Year Variance

(Constant 2022 $000)

Exhibit:	SCE-04 Resiliency
Volume:	5 Pt. 3 - Wildfire Management
Business Planning Element:	Wildfire Management
Activity:	Alternative Technologies
Witness:	A.Swisher/R.Fugere



Cost Type		Recorded/Adj.					Forecast		
		2018	2019	2020	2021	2022	2023	2024	2025
Recorded / Forecast	Labor	0	0	121	564	618	1,764	403	329
	Non-Labor	0	0	13	450	636	757	668	614
	Other	0	0	0	0	0	0	0	0
	Total	**0**	**0**	**135**	**1,013**	**1,254**	**2,522**	**1,071**	**942**

Labor	Prior Year Total	0	0	121	564	618	1,764	403
	Change	0	121	442	54	1,147	(1,362)	(74)
	Total	**0**	**121**	**564**	**618**	**1,764**	**403**	**329**

Non-Labor	Prior Year Total	0	0	13	450	636	757	668
	Change	0	13	436	187	121	(89)	(54)
	Total	**0**	**13**	**450**	**636**	**757**	**668**	**614**

Other	Prior Year Total	0	0	0	0	0	0	0
	Change	0	0	0	0	0	0	0
	Total	**0**	**0**	**0**	**0**	**0**	**0**	**0**

Total Change	Prior Year Total	0	0	135	1,013	1,254	2,522	1,071
	Change	0	135	879	241	1,268	(1,451)	(129)
	Total	**0**	**135**	**1,013**	**1,254**	**2,522**	**1,071**	**942**

Due to rounding, totals may not tie to individual items.

2025 GRC Forecast Commentary

(Constant 2022 $000)

Exhibit:	SCE-04 Resiliency
Volume:	5 Pt. 3 - Wildfire Management
Business Planning Element:	Wildfire Management
Activity:	Alternative Technologies
Witness:	A.Swisher/R.Fugere

Summary of Changes: See Testimony

Cost Type		Recorded/Adj.					Forecast		
		2018	2019	2020	2021	2022	2023	2024	2025
Recorded / Forecast	Labor	0	0	121	564	618	1,764	403	329
	Non-Labor	0	0	13	450	636	757	668	614
	Other	0	0	0	0	0	0	0	0
	Total	**0**	**0**	**135**	**1,013**	**1,254**	**2,522**	**1,071**	**942**

Due to rounding, totals may not tie to individual items.

Recorded (2018-2022)

See Testimony

Forecast (2023-2025)

See Testimony

Workpaper Title:

Remote Grid Workpaper Addendum

WP SCE-04 Vol. 05 Part 3

Remote Grid (RG) Workpaper Addendum

A	B	C	D	E	F	G	H
1	**O&M**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**
2	**Remote Grid Feasibility Studies**	**$ 120,000**	**$ 120,000**	**$ 150,000**	**$ -**	**$ -**	**$ -**
3	# of Locations	4	4	5			
4							
5	**Explanations and Assumptions -**						
6	Cost per RG Feasibility Study	$ 30,000					
7	Total O&M cost per year calculated as (Cost per RG Feasibility Study * # of Locations)						
8	The forecast incorporates accounting adjustments that include certain changes made to SCE's employee compensation program. Please refer to SCE-06, Vol. 04.						
9	Net amount of total adjustments	$ 9,780.72	$ 10,745.13	$ 16,026.93			

Workpaper Title:

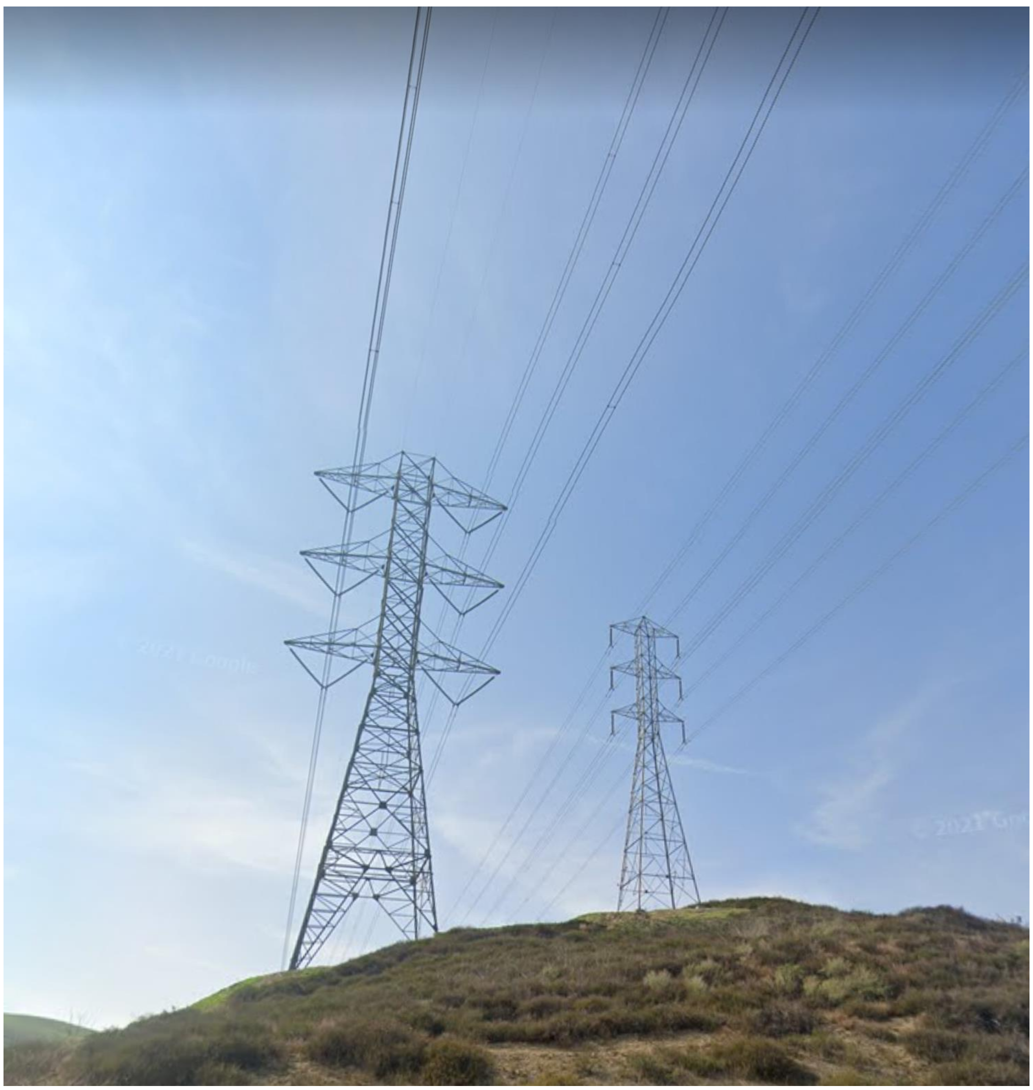
Transmission IWMS 2023 Workpaper

WP SCE-04 Vol. 05 Part 3

SOUTHERN CALIFORNIA EDISON An EDISON INTERNATIONAL Company	SOUTHERN CALIFORNIA EDISON			
	Wildfire Mitigation Strategy			
Transmission Integrated Wildfire Mitigation Strategy (IWMS)	Prepared by:	[redacted]	Date:	1/3/2023
	Reviewed by:	[redacted]	Date:	1/23/2023

Transmission Integrated Wildfire Mitigation Strategy (IWMS) Workpaper

January 3, 2023



SOUTHERN CALIFORNIA EDISON An EDISON INTERNATIONAL™ Company	SOUTHERN CALIFORNIA EDISON			
	Wildfire Mitigation Strategy			
Transmission Integrated Wildfire Mitigation Strategy (IWMS)	Prepared by:	[redacted]	Date:	1/3/2023
	Reviewed by:	[redacted]	Date:	1/23/2023

Table of Contents

SOUTHERN CALIFORNIA EDISON An EDISON INTERNATIONAL Company	SOUTHERN CALIFORNIA EDISON			
	Wildfire Mitigation Strategy			
Transmission Integrated Wildfire Mitigation Strategy (IWMS)	Prepared by:	[redacted]	Date:	1/3/2023
	Reviewed by:		Date:	1/23/2023

1.0: Summary

In 2023, Wildfire Safety will conduct Engineering Analysis and Testing to explore wildfire grid hardening solutions for the Transmission System in HFRA to include but not limited to:

- Enhanced System Design: upgrading poles to fire resistant structures, crossarm replacement, increased conductor spacing, etc.
- Covered conductor for sub-transmission
- Quantitative Risk Assessment for transmission overhead structures and components
- Feasibility and cost analysis comparison to undergrounding

This is a new activity, so Transmission IWMS Engineering Analysis and Testing was never included in the previous GRCs or WMPs. There is no regulatory requirement associated with this analysis effort, however, it will allow SCE to identify wildfire solutions on the Transmission System that would cost-effectively reduce wildfire ignition risk and increase reliability.

SOUTHERN CALIFORNIA EDISON An EDISON INTERNATIONAL℠ Company	SOUTHERN CALIFORNIA EDISON			
	Wildfire Mitigation Strategy			
Transmission Integrated Wildfire Mitigation Strategy (IWMS)	Prepared by:	[redacted]	Date:	1/3/2023
	Reviewed by:		Date:	1/23/2023

2.0: Background

Grid Hardening activities for Transmission systems had smaller scope in prior years (i.e., C-Hooks, Transmission Open Phase Detection, Early Fault Detection). In recent years, ignitions associated with the Transmission system are trending up. There are only a limited number of mitigations, such as undergrounding, readily available to address these risks. However, undergrounding the transmission system may take many years and the associated costs are steep. Engineering analysis and testing of new emerging technologies allows SCE to build a suite of mitigation options utilizing the Integrate Wildfire Mitigation Strategy (IWMS) risk tranche for the transmission system with the ultimate objective to reduce ignition risks in a cost-effective manner.

In February 2022 (for the 2022 WMP Update), SCE finalized the Integrated Wildfire Mitigation Strategy (IWMS)[1] to proactively target the highest consequence locations on the Distribution systems. Wildfire Safety is also evaluating the Transmission systems for wildfire risk and aligning it to the IWMS for the 2023-2025 Wildfire Mitigation Plan (WMP) and 2025 General Rate Case (GRC).

SCE analyzed the CPUC reportable ignition data for Transmission systems which includes voltages from 55kV to 500kV. When normalized for the number of miles in HFRA, SCE found that for every six Distribution ignition events, there is one Transmission ignition event as seen in Figure 1. Also, for Contact from Foreign Object (CFO) drivers only, for every four Distribution ignition events, there is one Transmission ignition event. While transmission lines have a lower probability of failure compared to distribution lines, there are still risks associated with ignitions that could propagate from a transmission line.

[1] At that time, the strategy was called Integrated Grid Hardening Strategy. We have included other wildfire mitigations, such as inspections, remediation, and vegetation management, into this strategy; hence, the name has been updated to Integrated Wildfire Mitigation Strategy or IWMS.

SOUTHERN CALIFORNIA EDISON An EDISON INTERNATIONAL Company	SOUTHERN CALIFORNIA EDISON			
	Wildfire Mitigation Strategy			
Transmission Integrated Wildfire Mitigation Strategy (IWMS)	Prepared by:	[redacted]	Date:	1/3/2023
	Reviewed by:		Date:	1/23/2023

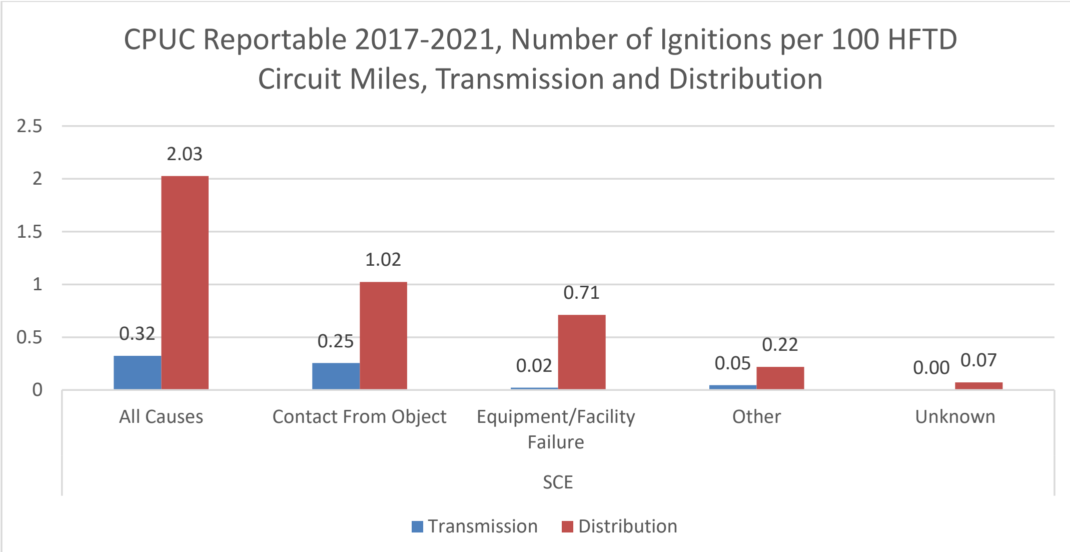


Figure 1: CPUC Reportable Ignitions Transmission and Distribution[2]

Currently, there are a limited number of tools currently available to SCE to address ignition risks associated with the Transmission system, such as Undergrounding, Transmission Open Phase Detection (applicable only to 220kV system), and Early Fault Detection (applicable only to 66kV and 115kV). This activity aims to explore the feasibility of implementing other mitigations on the Transmission system, by providing a feasibility and cost analysis of each potential mitigation.

3.0: Activities and Cost Estimates

In 2023, Wildfire Safety proposes to conduct Engineering Analysis and Testing to explore wildfire mitigation solutions for the Transmission System in HFRA to include but not limited to:

- Enhanced System Design
- Covered conductor for sub-transmission
- Quantitative Risk Assessment for transmission overhead structures and components

3.1 Enhanced System Design

The objective of the Enhanced System Design (ESD) is to harden the Transmission System on the structure level. There are three proposed levels of structure hardening, corresponding to each IWMS

[2] See Fire Ignition Data for SCE, available at https://www.cpuc.ca.gov/industries-and-topics/wildfires.

risk tranche: Level 3 may be applied to the IWMS Severe Risk Area, Level 2 to High Consequence, and Level 1 to Other HFRA as designated in the IWMS[3].

Enhanced System Design (ESD) Level 3

- Pole replacement (Light Weight Steel, Tubular Steel Pole)
- Cross arm replacement (post-type insulator, steel cross arm)
- Increased phase spacing
- Wildlife Protection Devices
- Covered jumpers
- Guy wire elimination, or Fiberglass Guy Strain Insulator (FGSI) guying
- Shield Wire, or Fault Return Conductor

Enhanced System Design (ESD) Level 2

- FR Wrap on existing poles
- Cross arm replacement (post-type insulator, steel cross arm)
- Increased phase spacing
- Wildlife Protection Devices
- Covered jumpers
- Fiberglass Guy Strain Insulator (FGSI) guying
- Shield Wire, or Fault Return Conductor

Enhanced System Design (ESD) Level 1

- Increased phase spacing
- Wildlife Protection Devices
- Covered jumpers
- Fiberglass Guy Strain Insulator (FGSI) guying
- Shield Wire, or Fault Return Conductor

The cost estimate for ESD totals $250,000 which includes design and testing of overall structure and components within ESD. This cost estimate calculated based on previous testing on pole structure is below.

A cost breakdown for the maximum cost total for the pole testing is given in the table below.

Protocol Development	$0. 0
Sample Preparation and Logistics	$14,000
Lab Facilities Equipment and Associated Personnel Fees	$65,000

[3] *See* SCE-04 Vol 5 Part 1 for a detailed description of IWMS.

Travel Expenses	$1,000
Data Analysis and Reporting	$0.0
Total	$80,000

Similar design and testing activities will be needed for new technologies on the ESD transmission system including crossarms, post type insulators, covered jumpers, and wildlife protection devices. Vendor estimates and previous testing for similar crossarms and post-type insulators amount to $80,000. Design and testing of covered jumpers and wildlife protection devices are based on vendor estimates and previous testing, estimated at $45,000 each.

3.2 Subtransmission Covered Conductor

Covered conductor refers to a conductor being "covered" with insulating materials to protect against the impacts of incidental contact. This mitigation is effective at reducing the ignition drivers associated with CFO and wire-to-wire faults on the distribution system. Currently, covered conductor can be deployed on voltage systems of 33kV and below. The development and testing of subtransmission covered conductor will be performed as part of this activity to determine if covered conductor is viable and cost effective on the 66kV subtransmission system.

The cost estimate for subtransmission covered conductor is $325,000 and is based on estimates for vendor Pole Loading Analysis and on previous vendor testing for distribution covered conductor.

3.3 Quantitative Risk Assessment (QRA)

Quantitative Risk Assessment (QRA) applies performance based engineering to determine the probability of failure and ignition of a system in respect to a given hazard. Hazards can be wind speed, age, electrical spacing, and ignitions due to foreign object contact.

The hazard curves integrate ignition driver data and subject matter expertise such as inspection data, engineering first principals, local wind conditions, environmental data (corrosion, decay zones, weather, critter zones), failure modes and effects analysis component testing data, and performance history (outage history, notifications, root cause, general asset data).

Quantitative Risk Assessment will be performed on the transmission system to determine overall mitigation effectiveness of solutions, failure modes, and mitigation effectiveness depreciation over time.

The cost estimate for performing Quantitative Risk Assessment is $700,000 and is based on vendor estimates for similar QRA studies performed for SCE.

4.0: Conclusion

In 2023, Wildfire Safety proposes to conduct Engineering Analysis and Testing to explore wildfire mitigation solutions for the Transmission System in HFRA to include but not limited to:

- Enhanced System Design: upgrading poles to fire resistant structures, crossarm replacement, increased conductor spacing
- Covered conductor for sub-transmission
- Quantitative Risk Assessment for transmission overhead structures and components

This allows SCE to identify wildfire solutions on the Transmission System that would cost-effectively reduce wildfire ignition risk and increase reliability.

Please refer to the Transmission IWMS Workpaper Addendum for a breakdown of the forecasted costs for this activity.

Workpaper Title:

Transmission IWMS 2023 Workpaper Addendum

WP SCE-04 Vol. 05 Part 3

Transmission Integrated Wildfire Mitigation Strategy (IWMS) Workpaper Addendum

A	B		C	D	E	F	G	H
1	**O&M**		**2023**	**2024**	**2025**	**2026**	**2027**	**2028**
2	Enhanced System Design (ESD)	$	250,000					
3	Sub-Transmission Covered Conductor	$	325,000					
4	Quantitative Risk Assessment	$	700,000					
5	**TOTAL**	**$**	**1,275,000**					
6								
7	**Explanations and Assumptions -**							
8	ESD Pole Structure Design & Testing	$	80,000.00					
9	ESD Cross-Arm, Post Type Insulator Design & Testing	$	80,000.00					
10	ESD Covered Jumpers	$	45,000.00					
11	ESD Critter Protection	$	45,000.00					
12	Enhanced System Design calculated as (ESD Pole Structure Design & Testing + ESD Cross-Arm, Post Type Insulator Design & Testing + ESD Covered Jumpers + ESD Critter Protection)							
13	The forecast incorporates accounting adjustments that include certain changes made to SCE's employee compensation program. Please refer to SCE-06, Vol. 04.							
14	Net amount of total adjustments	$	10,181					

Workpaper Title:

Transmission Open Phase Detection Workpaper

WP SCE-04 Vol. 05 Part 3

Transmission Open Phase Detection (TOPD) Workpaper

A	B	C	D	E	F	G	H
1	**O&M**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**
2	**Engineering Design, Protection execution, Test Support & CFF (Wiring Support)**	**$ 725,000**	**$ 412,500**	**-**	**-**	**-**	**-**
3	# of Locations	5	5	-	-	-	-
4							
5	**Explanations and Assumptions -**						
6	2023 Cost Per Location (New Installations) (GE current base approach)	$ 125,000					
7	2024 Cost Per Location (Retrofit) (GE current base approach)	$ 62,500					
8	GE RTDS/Setting Development Support per year	$ 100,000					
9	Estimated cost per location includes engineering, material, wiring, deployment and testing of the open phase detection algorithm.						
10	Cost to retrofit lines in 2024 by adding isolation functionality to lines that were previously engineered to alarm only is estimated at 50% of the overall project cost, since half of the installation work was already completed.						
11	2023 total cost calculated as (2023 Cost Per Location * # of Locations)+ GE RTDS/Setting Development Support per year						
12	2024 total cost calculated as (2024 Cost Per Location * # of Locations)+ GE RTDS/Setting Development Support per year.						
13	The forecast incorporates accounting adjustments that include certain changes made to SCE's employee compensation program. Please refer to SCE-06, Vol. 04.						
14	Net amount of total adjustments	$ (13,809)	$ (11,038)				

Workpaper Title:

Distribution Open Phase Detection Workpaper

WP SCE-04 Vol. 05 Part 3

Distribution Open Phase Detection (DOPD) Workpaper

A	B	C	D	E	F	G	H
1	**CAPITAL**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**
2	**Engineering Design, Material, Protection Execution, Construction and Apparatus Support**	**$ -**	**$ -**	**$ 1,500,000**	**$ 1,500,000**	**$ 1,500,000**	**$ 1,500,000**
3	# of Locations			12	12	12	12
4							
5	**Explanations and Assumptions -**						
6	Cost per Location (includes engineering, necessary infrastructure upgrades, deployment and testing of the open phase algorithm).	$ 125,000					
7	Deploying the logic on existing infrastructure may require upgrades such as controllers, voltage sensors and pole replacements in order to succesfully deploy the logic.						
8	Total Capital cost per year calculated as (Cost per Location * # of Locations).						
9	The forecast incorporates accounting adjustments that include certain changes made to SCE's employee compensation program. Please refer to SCE-06, Vol. 04.						
10	Net amount of total adjustments	$ -	$ -	$ 5	$ 5	$ 6	$ 5
11							
12	**O&M**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**
13	**Labor required to investigate and gather event data**	**$ 98,000**	**$ 98,000**	**$ 131,600**	**$ 165,200**	**$ 198,800**	**$ 232,400**
14	# Installed Locations	35	35	47	59	71	83
15							
16	**Explanations and Assumptions -**						
17	Labor cost for 1/2 day crew: Cost of event investigation and data gathering is estimated to require half of a crew day. Cost per full crew day is estimated at $7,000 so the cost of a 1/2 day crew is $3,500.	$ 3,500					
18	Expected Event Frequency: Assume that 80% of the installed units to have one event per year requiring labor investigation.	80%					
19	Installations at YE 2022 is 35 units.						
20	Increase in cost for years 2025 through 2028 is based on an increase in the install base of 12 locations per year starting in 2025.						
21	Total O&M cost per year calculated as (# Installed Locations * Expected Event Frequency * Labor cost for 1/2 day crew).						
22	The forecast incorporates accounting adjustments that include certain changes made to SCE's employee compensation program. Please refer to SCE-06, Vol. 04.						
23	Net amount of total adjustments	$ (4,049)	$ (6,906)	$ (13,298)	$ (20,960)	$ (30,209)	$ (41,038)

Workpaper Title:

Capital Detail for Distribution Open Phase Detection

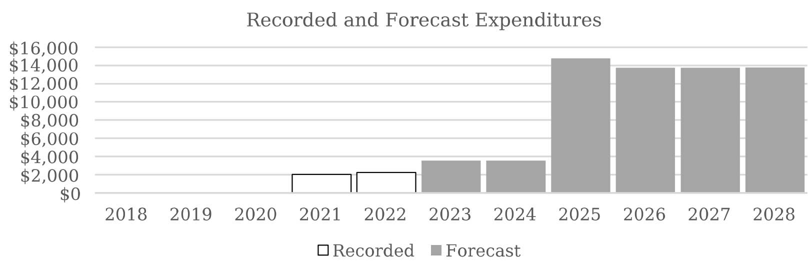
WP SCE-04 Vol. 05 Part 3

Southern California Edison - Capital Workpapers
Capital Workpapers Summary
SUMMARY BY GRC Volume
(Nominal $000)

Exhibit: SCE-04 Resiliency
Volume: 5 Pt. 3 - Wildfire Management

	Recorded Capital Expenditures					Forecast Capital Expenditures					
Description	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Recorded and Forecast Expenditures				2,015	2,243	3,528	3,522	14,758	13,741	13,742	13,773
Total Expenditures					4,258						63,063

Due to rounding, totals may not tie to individual items.



	Forecast Capital Expenditures						
GRC Activity	2023	2024	2025	2026	2027	2028	6 yr Total
Alternative Technologies	3,528	3,522	14,758	13,741	13,742	13,773	63,063
GRC Total	3,528	3,522	14,758	13,741	13,742	13,773	63,063

Southern California Edison
2025 GRC Capital Workpapers

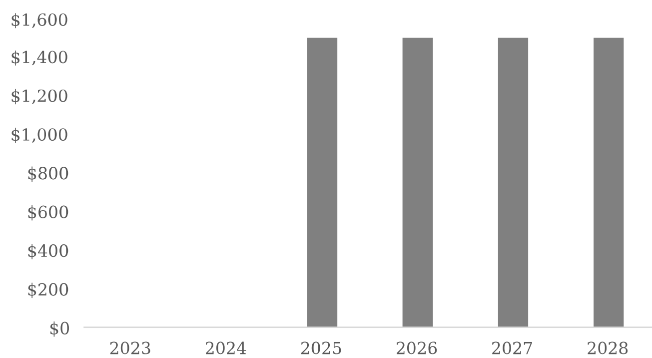
Exhibit:	SCE-04 Resiliency
Volume:	5 Pt. 3 - Wildfire Management
Business Plan Group:	Resiliency
Business Plan Element:	Wildfire Management
GRC Activity:	Alternative Technologies
1. Witness:	Andrew Swisher
2. Asset type:	DS-LINE
3. In-Service date:	12\1\9999
4. RO Model ID:	1014
5. Pin:	8224
6. CWBS Element:	CETPDWMDT822403
CWBS Description:	Distribution Open Phase Detection
7. SRIIM Eligible:	No

Cost Estimates - Nominal ($000)

2025 GRC - Capital Expenditures Forecast

Year	2023	2024	2025	2026	2027	2028	2023 - 2028 Total
SCE$	0	0	1,500	1,500	1,500	1,500	6,000

Due to rounding, totals may not tie to individual items.



Workpaper Title:

Early Fault Detection Workpaper

WP SCE-04 Vol. 05 Part 3

Early Fault Detection (EFD) Workpaper

A	B	C	D	E	F	G	H
1	**CAPITAL**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**
2	**Engineering Design, Material, Construction and Automation Support**	**$ 3,500,000**	**$ 3,500,000**	**$ 12,050,000**	**$ 11,050,000**	**$ 11,050,000**	**$ 11,050,000**
3	# of EFD Units	100	100	300	300	300	300
4							
5	**Explanations and Assumptions -**						
6	Cost Per Location: Includes design, material, required permits, construction, establishing communication and end-point testing. The breakdown of costs would be approximately 40% for procuring material and 60% for construction.	$ 35,000					
7	2025 Acoustic Camera Purchase Cost.	$ 1,000,000					
8	2023 and 2024 Total Capital cost per year calculated as (Cost Per Location * # of EFD Units).						
9	2025 Total Capital cost calculated as [Engineering Design, Material, Construction and Automation Support + 2025 Acoustic Camera Purchase Cost].						
10	2025, 2026, 2027, 2028 Total Capital costs are consistent with capital EFD costs in RAMP filing						
11	The forecast incorporates accounting adjustments that include certain changes made to SCE's employee compensation program. Please refer to SCE-06, Vol. 04.						
12	Net amount of total adjustments	$ 27,950.70	$ 21,505.13	$ 17,762.69	$ (116)	$ 3,078	$ 31,844.09
13							
14	**O&M**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**
15	Service Fee	$ 150,000	$ 196,000	$ 300,000	$ 400,000	$ 700,000	$ 1,000,000
16	Field Labor required to investigate, gather event data and minor remediation	$ 50,120	$ 56,000	$ 133,000	$ 154,000	$ 175,000	$ 196,000
17	Continous monitoring, operation and maintenance of EFD System	-	$ 100,000	$ 100,000	$ 300,000	$ 300,000	$ 300,000
18	# of Installed EFD Units (≤ 1 year)	104	100	300	300	300	300
19	# of Installed EFD Units (> 1 year)	196	300	400	700	1000	1300
20	# of Installed EFD Units with Service Charge Incurred	150	196	300	400	700	1000
21	**Totals**	**$ 200,120**	**$ 352,000**	**$ 533,000**	**$ 854,000**	**$ 1,175,000**	**$ 1,496,000**
22							
23	**Explanations and Assumptions -**						
24	Service Charge: The cost of working with external vendors to host/support EFD data. An O&M service fee is incurred two years after the in-service date.	$ 1,000					
25	Assumed Find Rate ≤ 1 year: The assumed rate of detections by EFD units that have been in-service for a year or less.	10%					
26	Assumed Find Rate > 1 year: The assumed rate of detections by EFD units that have been in-service for more than one year.	2%					
27	Labor cost for 1/2 day crew: Cost of event investigation and data gathering is estimated to require half of a crew day. Cost per full crew day is estimated at $7,000 so the cost of a 1/2 day crew is $3,500.	$ 3,500					
28	Continous monitoring, operations and maintenance of install base: This activity is for non-field labor to provide data analysis and program support and oversight of EFD. In 2023, there are no costs for this activity as the costs will be absorbed by existing engineering functions. In 2024 and beyond, the costs are commensurate with the amount of work required to monitor additional EFD units. In 2026 and beyond, the costs include evaluations for potential FAN integration and other IT services/evaluations.						
29	Service Fee calculated as (# of Installed EFD Units with Service Charge Incurred * Service Charge).						
30	Field Labor calculated as [(# of Installed EFD Units (≤ 1 year)*Assumed Find Rate ≤ 1 year) + (# of Installed EFD Units (> 1 year)*Assumed Find Rate > 1 year)] * Labor cost for 1/2 day crew.						
31	Total O&M Cost calculated as Service Fee + Field Labor + Continous monitoring, operation and maintenance.						
32	The forecast incorporates accounting adjustments that include certain changes made to SCE's employee compensation program. Please refer to SCE-06, Vol. 04.						
33	Net amount of total adjustments	$ (2,008)	$ (10,033)	$ (21,659)	$ (58,238)	$ (84,985)	$ (122,786)

Workpaper Title:

Capital Detail for Early Fault Detection

WP SCE-04 Vol. 05 Part 3

Southern California Edison - Capital Workpapers
Capital Workpapers Summary
SUMMARY BY GRC Volume
(Nominal $000)

Exhibit: SCE-04 Resiliency
Volume: 5 Pt. 3 - Wildfire Management

	Recorded Capital Expenditures					Forecast Capital Expenditures					
Description	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Recorded and Forecast Expenditures				2,015	2,243	3,528	3,522	14,758	13,741	13,742	13,773
Total Expenditures					**4,258**						**63,063**

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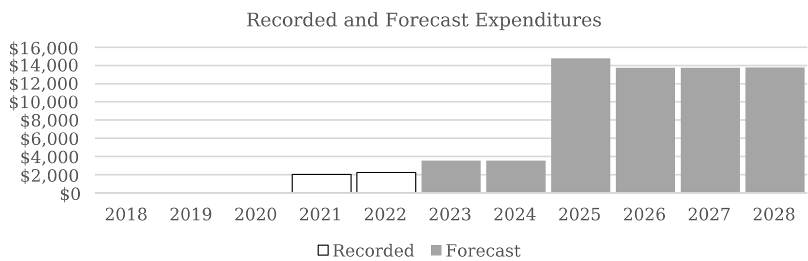


	Forecast Capital Expenditures						
GRC Activity	2023	2024	2025	2026	2027	2028	6 yr Total
Alternative Technologies	3,528	3,522	14,758	13,741	13,742	13,773	63,063
GRC Total	3,528	3,522	14,758	13,741	13,742	13,773	63,063

Southern California Edison
2025 GRC Capital Workpapers

Exhibit:	SCE-04 Resiliency
Volume:	5 Pt. 3 - Wildfire Management
Business Plan Group:	Resiliency
Business Plan Element:	Wildfire Management
GRC Activity:	Alternative Technologies

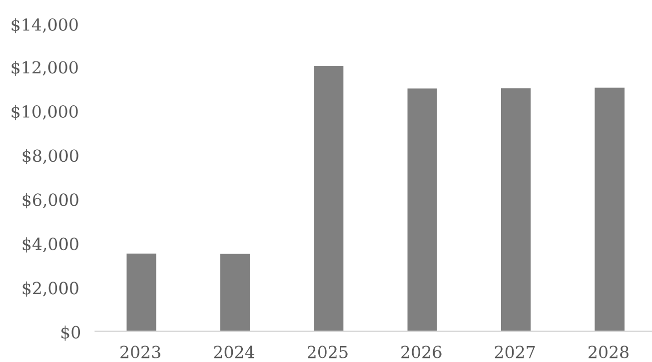
1. Witness:	Andrew Swisher
2. Asset type:	DS-LINE
3. In-Service date:	12\1\9999
4. RO Model ID:	975
5. Pin:	8224
6. CWBS Element:	CETPDWMDT822402
CWBS Description:	Early Fault Detection
7. SRIIM Eligible:	No

Cost Estimates - Nominal ($000)

2025 GRC - Capital Expenditures Forecast

Year	2023	2024	2025	2026	2027	2028	2023 - 2028 Total
SCE$	3,528	3,522	12,068	11,050	11,053	11,082	52,302

Due to rounding, totals may not tie to individual items.



Workpaper Title:

High-Impedance Relays—Field Tests and Dependability Analysis

WP SCE-04 Vol. 05 Part 3

High-Impedance Fault Detection—Field Tests and Dependability Analysis

Daqing Hou
Schweitzer Engineering Laboratories, Inc.

Presented at the
36th Annual Western Protective Relay Conference
Spokane, Washington
October 20–22, 2009

High-Impedance Fault Detection—Field Tests and Dependability Analysis

Daqing Hou, *Schweitzer Engineering Laboratories, Inc.*

***Abstract*—Because of low-fault currents, high-impedance faults neither interrupt service to customers nor cause thermal damage to power system equipment. However, high-impedance faults resulting from downed conductors are potentially hazardous to humans and livestock and are a concern for public safety. A high-impedance fault should be rapidly isolated when detected. Traditional substation–based overcurrent protection relays reliably detect high-current, short-circuit faults. The same cannot be said about substation-based high-impedance fault detection devices because of low or nearly zero fault current. In some situations, the standing load unbalance in multigrounded systems can be higher than the high-impedance fault current. Therefore, the detection rate of a high-impedance fault is often used to verify the presence of a high-impedance fault. This paper uses several high-impedance fault field tests to explain how to develop a detection rate and answers the question of whether there is a detection rate applicable for all circumstances. The paper first introduces details of the field tests: test setups, weather conditions, ground materials, and fault currents. It then provides comparative test results. Finally, the paper analyzes the security and dependability of high-impedance fault detection and provides the reader with insight into the statistical detection rate.**

I. Introduction

High-impedance faults are those with a high resistance in the fault path. The value of the fault resistance for a fault defined as a high-impedance fault depends on interpretation and circumstances. For the purpose of this paper, high-impedance faults are ground faults that produce fault currents below the traditional ground overcurrent element pickup level.

Some typical causes of high-impedance faults are listed below:

- incipient insulator failure
- trees or bushes that come into contact with overhead power lines
- conductors that fall onto poorly conductive surfaces

For distribution networks with voltage levels lower than 35 kV, high-impedance faults resulting from downed conductors are a concern for public safety. High-impedance faults do not cause traditional ground overcurrent elements to operate, so these faults can exist in a distribution system for an extensive period without being detected. The small current from a high-impedance fault does not impact normal power distribution, but such a fault can appear so harmless that humans or livestock can be electrocuted from accidental contact with a downed conductor. The downed conductor can also cause fire damage to structures and other properties.

Since the early 1970s, the problem of high-impedance faults has caught the attention of the public as well as that of protection engineers. Over time, utilities worldwide have conducted many field tests to support research and development of detection algorithms for these low-current faults. Today, there are several commercial devices available that can increase the possibility of detecting these faults.

As we shall see, high-impedance faults are dynamic and random. Some downed conductors cause no fault current to flow. Therefore, substation-based detection devices will not reliably detect all downed conductor or high-impedance faults. The tangible objective in dealing with high-impedance faults is to increase the possibility of fault detection while maintaining detection security.

Because of this nondeterministic detection of less than 100 percent, the first thing we generally discuss when evaluating high-impedance fault detection devices is the so-called fault detection rate. What percentage of high-impedance faults can a particular device detect? Some relay manufacturers have associated values ranging from 80 percent or even closer to 100 percent to their devices.

In this paper, we look at some details of several high-impedance field fault tests and summarize the results. The aim of this paper is to evaluate the validity of any specific number associated to the detection rate. So that the reader can better appreciate the challenges of high-impedance fault detection, we shall first provide some background on high-impedance faults. We will discuss how different system grounding schemes govern the best fault detection methods and provide some high-impedance fault detection fundamentals.

II. High-Impedance Faults

High-impedance faults generate low-fault currents. Field tests on distribution systems in North America with a typical voltage of 12.5 kV indicate that fault currents of high-impedance faults are less than 100 A. Higher distribution voltage tends to increase the fault current and cause less high-impedance fault concerns.

The fault current level relates closely to the type of ground surfaces that a conductor touches. The level also depends on the ground surface moisture level. Other factors such as surrounding soil types and nearby structures also impact the fault current level. Fig. 1 summarizes the fault current ranges for different ground surface materials when a bare conductor touches them [1]. We see that asphalt and dry sand are good insulators. There is no measurable fault current when a conductor touches these surface materials. By using 12.5 kV as the mean test voltage, we can conclude that the minimum high-impedance fault resistance (approximately 95 Ω) is for reinforced concrete.

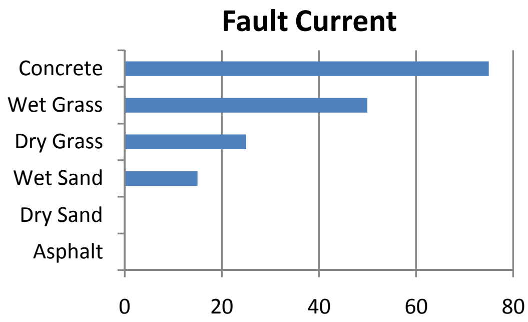


Fig. 1. High-impedance fault currents depend on ground surface types

High-impedance fault currents are rich in harmonics and nonharmonic content. The harmonic content results from a fault that involves an arcing process. In their experiments of electric arcs, Kuffman and Page [2] found that the arc current starts to flow when the applied voltage reaches a breakdown voltage level of an air gap. The arc current continues to flow after the applied voltage is less than the breakdown voltage level and until satisfaction of an equal-area criterion. The voltage across the arc remains constant when arc current flows. The arc can restrike during the next half cycle when the voltage reaches the breakdown voltage level again. The upper plot of Fig. 2 shows a fault current from a downed conductor on bare ground. The lower plot shows the large percentage of odd harmonics resulting from arcing activities.

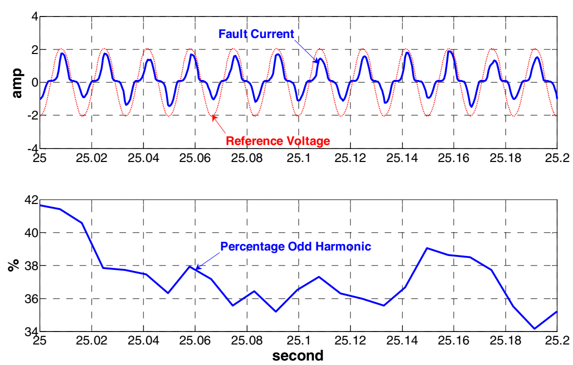


Fig. 2. High-impedance fault current contains rich harmonic content

High-impedance faults have a dynamic behavior. The heat generated by the arcing fault tends to remove moisture in most ground surfaces. The high temperature can cause chemical reactions that change surface conductivity. The electromagnetic force associated with arcing can also make the downed conductor move about. Different seasons and different times of day can also impact ground surface conductivity. These dynamic characteristics of high-impedance faults change the level and content of fault currents accordingly and make fault detection a random process.

III. System Grounding and High-Impedance Fault Detection

Distribution systems use different grounding methods to achieve the following objectives [3]:

- minimize equipment voltage stress
- minimize equipment thermal stress
- provide personnel safety
- reduce interference to communications systems
- assist with quick detection and isolation of ground faults

Other factors such as overall system cost and service delivery reliability also influence the selection of grounding methods.

Over time, distribution systems have used many ground methods. The practice of grounding the system seems more localized, as references [3] and [4] indicate. Each region normally has its own preferable grounding scheme, although some grounding methods are more common for industrial plants. Grounding methods include the following:

- ungrounded or isolated neutral
- resonant grounding
- high-resistance grounding
- effective (solid) grounding (includes unigrounding or multigrounding)
- low-impedance grounding

The first three grounding methods (ungrounded, resonant, and high-resistance grounded) have similar characteristics. We sometimes refer to these as small ground-fault-current, or small-current, grounding methods. By contrast, we refer to the last two grounding methods (effective [solid] and low-impedance groundings) as large-current groundings. These methods possess characteristics almost opposite those for small-current grounded systems.

There is no single grounding scheme that can achieve every objective listed previously. Each grounding method brings certain benefits but sacrifices other properties.

A. Small Ground-Fault-Current Systems

Ungrounded systems, as Fig. 3 shows, have no intentional grounding. Fault resistance and stray capacitances of distribution transformers and feeders determine the ground fault current. The fault current is normally quite small. Some of the benefits of ungrounded systems include minimum equipment thermal stress, continued service during a single ground fault condition, and self-extinction of ground faults when the capacitive fault current is small.

The stray capacitance of a large ungrounded system can support enough fault current so that a fault is less likely to self-extinguish. In this situation, we can connect a reactor known as a Petersen or arc-suppressing coil to the neutral point of a station transformer. The reactor is ideally tuned to match the system phase-to-ground capacitance, thereby reducing the fault current to about three percent to 10 percent of an ungrounded system.

To reduce transient overvoltage in an ungrounded system, we can connect a resistance to the neutral point of a station transformer to obtain a high-resistance grounded system. The resistance value is typically equal to or slightly less than one-third of the total system zero-sequence capacitance. This limits the transient overvoltage to less than 2.5 times the peak nominal phase-to-ground voltage and keeps the ground fault current to less than 25 A.

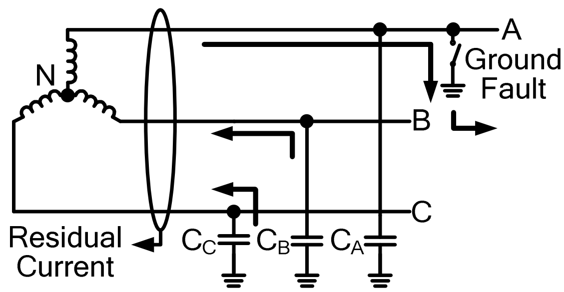


Fig. 3. An ungrounded distribution system

These three grounded schemes (ungrounded, resonant grounded, and high-resistance grounded) limit ground fault current to such a small value as to pose a challenge for selective and fast ground fault protections.

However, as microprocessor-based relays improve their measurement sensitivity, and relay manufacturers design improved detection algorithms, ground faults on these types of grounded systems become easier to detect.

All loads on these systems are connected phase-to-phase, which makes it easier to detect high-impedance faults. There is no residual current from loads. The asymmetry of feeders, transformers, and other equipment causes some standing residual current, but these unbalances are usually very small.

Reference [3] reports that directional overcurrent elements designed specifically for ungrounded systems can detect ground faults with tens of kilohms of fault resistance. The same reference also introduces a delta conductance element that can detect an 80 kΩ fault on a simulated resonant grounded system. In addition to deterministic detection of ground faults, reference [5] also shows faulted-phase selection logic that indicates reliably which phase is at fault.

System standing unbalance and measurement errors determine ground fault detection sensitivity. Use a dedicated toroidal current transformer (CT) to eliminate measurement unbalance error from three phase CTs as one way to improve system sensitivity. Dedicated toroidal CTs also allow a lower CT ratio, to increase the residual current measurement sensitivity of protective relays.

Notice that we define high-impedance faults as those ground faults with fault current less than traditional overcurrent pickups. In this sense, we can categorize many ground faults with large fault resistances in these small fault-current systems as normal ground faults that we can detect reliably.

B. Large Ground Fault-Current Systems

An IEEE standard [6] specifies that effectively grounded systems comply with $(X0/X1) \leq 3$ and $(R0/X1) \leq 1$, where X0 and R0 are the zero-sequence reactance and resistance, and X1 is the positive-sequence reactance of the system. Solidly grounded systems have their neutral point of the station transformer connected to the ground without intentional grounding impedance. A solidly grounded system may not be effectively grounded, depending on the quality of the grounding. A well-designed, solidly grounded system should also be an effectively grounded system.

Solidly grounded systems can be unigrounded or multigrounded. Unigrounded systems have a single grounding point typically at the station transformer neutral point. This type of system can be a four-wire system with a neutral wire brought outside the substation, or a three-wire system without the neutral wire. Some utilities connect small loads from a phase wire directly to the ground in unigrounded systems.

Another type of solidly grounded system is a four-wire multiple-grounded system such as Fig. 4 shows. To ensure an effective grounding, a multigrounded system typically grounds its neutral wire at every distribution transformer location and/or regularly about every 1000 feet, if there is no transformer ground point.

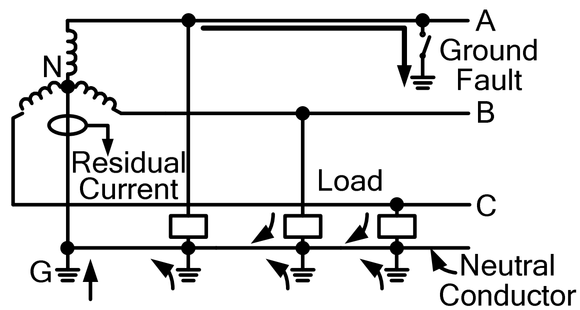


Fig. 4. A multigrounded distribution system

To reduce the ground fault current level for systems with small zero-sequence source impedance, we can use a low-impedance resistor or a reactor to ground the station transformer. This low-impedance grounding typically limits fault current to 100 A–1000 A to reduce thermal stress on equipment.

Solidly grounded systems limit the risk of overvoltages during ground faults and reduce equipment cost; necessary equipment insulation levels can be 1.73 times less than for small current grounding systems.

The drawback of these large current grounding schemes is that single-phase loads produce large standing unbalance that flows in the same path as the ground fault current (Fig. 4). This large standing unbalance therefore reduces ground fault detection sensitivity. System operating engineers do a good job of balancing overall system loads to minimize the amount of standing residual current. However, ground fault protection must consider the worst possible unbalance, because a fault can occur when a large single-phase lateral is out of service.

It should be clear by now that the determining factor for high-impedance fault detection is not the available ground fault current (fault duty) of a distribution system, but the worst system standing unbalance during normal operations. Solidly grounded and low-impedance grounded systems have a much greater ground fault duty than do small-current systems. However, at the fault resistance level of high-impedance faults, the fault currents that large-current systems provide drop to almost the values for small-current systems. It is the worst possible standing unbalance of the large-current systems that makes the detection of high-impedance faults a daunting task.

IV. High-impedance fault detection of Solidly grounded distribution systems

A. Traditional Ground Fault Protection Considerations

To improve protection sensitivities for the most common single-phase ground faults, utilities have been using low-set ground relays [7]. These ground relays work on a residual current that they either calculate by summing the three phase currents or measure directly from a residual connection.

However, the great number of single-phase loads can cause multigrounded distribution systems to be quite unbalanced. Even worse, the amount of load unbalance is dynamic and changes with system operation conditions. As an example, the three-phase loads at a substation may be well balanced. After a permanent fault occurs on a single-phase lateral, and the fuse clears the line, the system loads may become unbalanced. This increased residual current from a lateral outage may inadvertently operate a feeder relay at the substation.

As a consequence, utility engineers consider the worst system load unbalance when setting the pickup of a ground relay. The worst load unbalance, on top of the considerations of cold load pickup, transformer inrushes, and coordination with downstream ground relays, makes the ground relay protections not as promising as they initially seemed to be. Some utilities have even quit using all ground relays because of unpredictable load unbalances. Of utilities that use ground relays, a survey [7] indicates that engineers often set the ground relay pickups as a percentage of estimated load unbalance, a percentage of phase relay pickups, or a percentage of feeder load rating. The protection functions of these ground relays for high-impedance faults are therefore diminished.

B. High-Impedance Fault Detections

High-impedance faults have fault current less than 100 A. These faults are masked by load unbalances in solidly grounded distribution systems. Traditional ground overcurrent elements cannot detect these faults. To detect these faults, we must use detection algorithms that use current characteristics other than magnitude.

Arcing activity often accompanies high-impedance faults because of poor conductor contacts to a ground surface or because of poor conductivity of the ground surface itself. These arcing activities, together with the dynamic nature of the high-impedance fault, are responsible for the large harmonic and nonharmonic content in the fault current. For this reason, most high-impedance fault detection algorithms use the harmonic or nonharmonic content of the fault current.

We must understand that some nonlinear loads in distribution systems generate harmonic and nonharmonic current under normal operating conditions. An extreme example of a noisy load is an electric arc furnace such as foundries use for cast metal production. Other noisy loads include rail train, motor drives, car crushers, and switched power supplies used in modern electronic equipment.

For high-impedance fault detection algorithms that use non-fundamental quantities, the difference between nonharmonic quantities from normal load and a fault will impact the sensitivity of fault detection. This impact is similar to that of load unbalance on traditional ground overcurrent protection. To minimize this impact, a detection algorithm should employ additional technologies to differentiate high-impedance faults from normal noisy loads.

Many technologies have been used for detecting high-impedance faults. These include statistical hypothesis tests, inductive reasoning and expert systems, neural networks, third harmonic angle analysis, wavelet decomposition, decision trees, and fuzzy logic [8]. Regardless of many available advanced detection algorithms, the detection of high-impedance faults remains a challenging problem.

It is important to realize that it is impossible to detect all high-impedance faults with a substation-based device. For those downed conductor faults involving asphalt and dry sand that produce no fault currents, only distributed detection solutions aided by communication and customer calls can provide a complete solution.

Reference [8] proposes a detection algorithm that has a realistic objective in mind. This objective is to increase high-impedance fault detection as much as possible on top of traditional ground fault protections, while maintaining detection security. We have identified the following key elements as necessary for a successful detection algorithm:

- An informative quantity, such as the nonharmonic content of fault current, that reveals high-impedance fault signatures while remaining immune to noisy loads.
- A stable reference for the quantity that effectively quantifies prefault conditions.
- An adaptive learning feature that characterizes each feeder ambient condition while allowing seasonal load changes.
- An effective decision logic that further screens high-impedance fault properties such as the dynamic nature of the faults.

Fig. 5 shows the block diagram of the proposed detection algorithm.

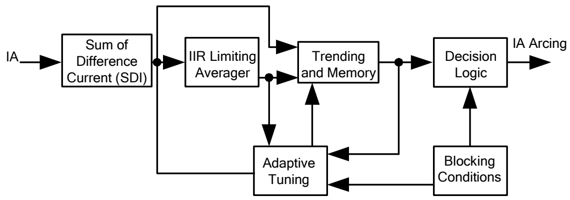


Fig. 5. Block diagram of high-impedance fault detection

The first function block calculates a signal quantity upon which the algorithm bases its high-impedance fault detection. This quantity is called the sum of difference current (SDI). An infinite-impulse-response (IIR) limiting averager then establishes a stable reference for SDI. The trending and memory block compares the present SDI with the SDI average and memorizes the time and ratio of the present SDI, if the present SDI is greater than a set threshold for the SDI average. The decision logic uses the results from the trending and memory block to determine the existence of a high-impedance fault on the processed phase. The adaptive tuning block monitors feeder background noise during normal system operations and establishes a comparison threshold for the trending and memory block. The IIR limiting averager also uses this threshold to prevent the averager input magnitude from becoming too large.

V. Field High-Impedance Fault Tests

Because of the dynamic and random nature of high-impedance faults, it is quite difficult to simulate these faults. We have seen some complex models that use nonlinear resistors and diodes to emulate the arcing phenomenon, but the validity of these models remains questionable in studying high-impedance faults.

There are many factors that impact the outcome of a downed conductor high-impedance fault. Among these factors are the type of ground surface, moisture content, condition of the surface, the voltage level, the type and size of conductor, the weather conditions, and humidity. It would be misleading, for example, if we referred to a ground surface as gravel without giving additional details such as the size of rock fragments, the thickness of the gravel surface, and the purity and types of gravel.

To study high-impedance faults and test the fault detection algorithm, we performed several staged fault tests with different utilities. These tests covered a large geographical region in North America and one in South America. Some of the tests are similar to those reference [9] describes. Table I shows the summary of these tests.

TABLE I.
SUMMARY OF HIF TESTS

Test	Test Date (Y,M,D)	Voltage Level	Distance	Temperature	Humidity	Test Surfaces[a]	Notes
A(1)	20050607	13.2 kV	12.7 mi	90°F	Humid	e, s, c, a, g, tr	Shower day before test.
A(2)	20050608	13.2 kV	1.8 mi	90°F	Humid	e, s, c, a, g, tr, ti	Shower night before test.
B	20050611	13.8 kV	13.9 mi	90°F	Dry	e	Dry season.
C	20050903	13.8 kV	13.9 mi	63°F	~70 %	e	Rainy season, wet ground.
D	20050623	12.5 kV	1.0 mi	80°F	Dry	e, c, g, tr, ti	Wet ground from sprinklers.
E(1)	20080826	13.2 kV	12.7 mi	92°F	Humid	e, s, c, a, g, tr	Hot and humid.
E(2)	20080827	13.2 kV	1.8 mi	95°F	~60 %	e, s, c, a, g, tr, ti	Hot and humid.
F	20090806	13.8 kV	7.3 mi	80°F	Rain	c, g	Rains on and off.

[a] e–earth, s–sand, c–concrete, a–asphalt, g–gravel, tr–tree, ti–tire

We used data acquisition systems that sampled currents and voltages at 20 kHz to record all tests. Normally, we recorded three-phase voltages and currents of the feeder under test and the fault current and voltage at the test site. In Test E, we also recorded the voltage and current at a location between the substation and the test site and those of one healthy feeder in the same substation. In the later E and F tests, we used GPS receivers to synchronize the data recordings of different locations. We attempted to record 1 minute prefault data and 3-minute fault data (or as long as a downed conductor fault could hold without blowing a fuse).

We performed all tests by lowering an energized conductor to a test surface with either a hot rod or control ropes. This test process is designed for personal safety and to control a test on a relatively small pre-made test surface. Reference [9] provides details of tests similar to those in Table I. In Test B, we initially dropped a covered or stripped conductor on the ground to emulate a downed conductor situation. However, the conductor was eventually held to the ground to make a better contact for larger fault currents.

Test A includes two test locations. A(1) is about 12.7 miles from the substation, and A(2) is about 1.8 miles from the substation. We performed Test E three years later on the same feeder and at the same two locations. The weather and ground conditions are very similar in both tests. The test method and the ground surfaces we used are exactly the same for both tests.

Table II and Table III show the fault currents of Test A and Test E. These results should be comparable because of similar test and weather conditions. However, we observed several differences. The earth fault in Test E produced more fault currents than Test A. This is surprising, especially when there was a rainstorm the night before Test A(2). The concrete fault yielded opposite results. The average fault current of Test A is more than that of Test E. We do not recall any differences with the reinforced concrete pads for both tests.

It is hard to compare the results of gravel tests. This is because we constantly changed such surface conditions as thickness and moisture content to try to get different results. When the gravel layer is too thin, the arc may also find a path directly to the ground and invalidate the test as a true gravel test.

The same can be said regarding the tree tests. Because of the variance of tree samples and the length of a test, it is hard to compare a tree fault even at the same location. Reports indicate that developing a fault on a tree limb takes time that depends on the voltage level, the moisture content, and the length of the tree limb. Once we establish a carbon track, however, fault current increases quickly. The current levels listed in the following tables are for well-established faults with arcs passing through the tree limb between the conductor and the ground.

TABLE II
AVERAGE FAULT CURRENTS FOR REMOTE TEST SITE

Test	Earth	Concrete	Wet Gravel	Tree
A(1)	32	10	25	16
E(1)	55	8	30	40

TABLE III
AVERAGE FAULT CURRENTS FOR CLOSE TEST SITE

Test	Earth	Concrete	Wet Gravel	Tree	Tire
A(2)	40	28	14	38	20
E(2)	70	10	12	10	15

We conducted Test B and Test C on the same feeder and at the same location. These two tests are three months apart, but Test B is in the dry season of the region and Test C is in the rainy season. Both tests include a covered conductor (tree wire) on the ground, stripped (bare) conductor on the ground, wet ground, and grounding rod(s). Note that there is no standard on the insulation level of the covered conductors. The cover is to prevent faults from tree limbs touching an overhead conductor.

From Table IV, we see an increased fault current level for the rainy season Test C. The "wet earth" in the table refers to ground that is very wet, almost like a mud hole. Finally, we used one 1-meter ground rod for Test B and three 1-meter ground rods for Test C.

TABLE IV
AVERAGE FAULT CURRENTS OF TEST B AND C

Test	Earth	Wet Earth	Ground Rod(s)
B	3	5	5
C	10	20	35

Table V lists the average fault current magnitudes of Test D for different ground surfaces. The test site was at the utility operating training center, where a sprinkler system was available. The ground is not wet during the test, but, given the high fault current magnitude of the earth test, the adjacent area was probably saturated. The gravel the test used is close to railroad gravel, which has larger size pieces than those we used in Test A and Test E.

One interesting note from Test D is that a test on a wet tire generated no fault current during a 2-minute test. Fig. 6 shows a picture of this test. The tire was a recently swapped-out used minivan tire we obtained from a tire center. This test is quite different from that of Test E for a dry tire, in which the tire caught fire immediately after the energized conductor touched it, as Fig. 7 shows. The tire we used in Test E was also a recently swapped out small truck tire.

TABLE V
AVERAGE FAULT CURRENTS OF TEST D

Test	Earth	Concrete	Gravel	Tree	Tire
D	145	10	3	70	0

Fig. 6. Wet tire test – no fault current during a 2-minute downed conductor

Fig. 7. Dry tire test –generates 15 A fault current immediately

Test F is the only test we conducted on a unigrounded distribution system. The utility reports that most urban loads are fed by three-phase delta/grounded-wye distribution transformers. However, in rural areas, some loads can be 500 km away from a substation. These remote loads are fed single-phase to the ground and may produce as much as 40 A to 60 A standing unbalance.

The test location is close to a coastal area where short and sudden storms are common. The ground was quite wet from showers just before the test. Table VI shows the fault current on two test surfaces: concrete and gravel. The concrete test was short because of a 6 A fuse blow. The 15 A gravel fault current came from an average 3-inch-thick wet gravel pile.

TABLE VI
AVERAGE FAULT CURRENTS OF TEST F

Test	Concrete	Wet Gravel
F	22	15

Several tests include asphalt as a test surface. Asphalt is a good insulator. Regardless of how long we performed a test or how wet the surface was, asphalt tests generated no fault current. We would have measured nothing at the substation, so it is easy to understand that no substation-based detection device will detect this type of fault.

Some tests also included sand as a ground surface. Dry sand is also a good insulator. An energized conductor on a 2-inch layer of dry sand did not produce any fault current. When we made the sand wet or made the sand layer thinner, the test results became more unpredictable. The upper plot of Fig. 8 shows a typical fault current from a 2-inch wet sand test. The lower plot of Fig. 8 shows the faulted phase current at the substation. The upper and lower plots are time synchronized. We observe that the fault current can increase suddenly when it finds a good conductive path. When the heat fuses the sand into silicon composite and changes the conductivity, the fault current drops. Some conductor movements by the test operator may also play a role in finding some good conductive paths.

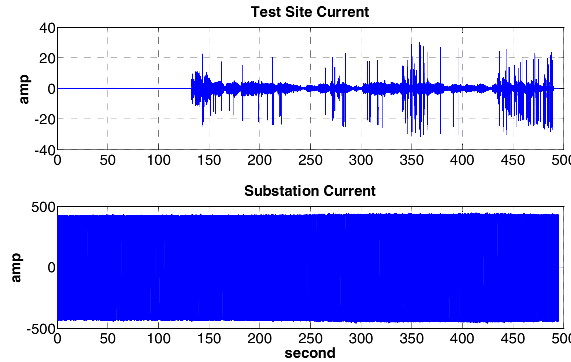


Fig. 8. Typical fault current of wet 2-inch layer sand

VI. THE MYSTERIOUS DETECTION RATE

Because a substation-based device cannot detect all high-impedance faults, we tend to use a number or a so-called detection rate to describe the percentage of high-impedance faults that a device can detect. Some device manufacturers have claimed 80 percent detection from their devices, and others even claim a detection rate close to 100 percent.

We have seen in previous sections that a downed conductor on dry sand and asphalt produces no fault current. So what can we claim regarding the detection rate of downed conductor faults in an urban area that unfortunately has mostly asphalt pavement? In the following discussion, we use several comparable cases as examples to demonstrate the complications of detecting high-impedance faults.

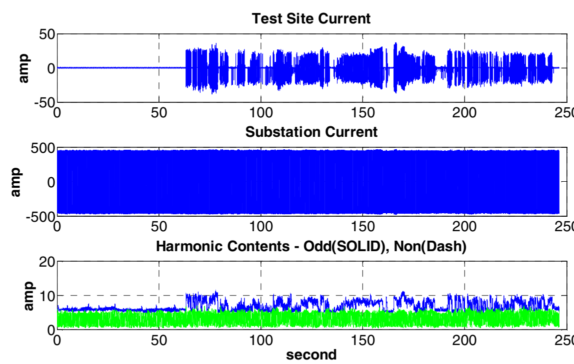


Fig. 9. A gravel fault from Test E(1)

The first example is for gravel faults. Fig. 9 shows a gravel test from Test E(1). The upper plot is the fault current at the test site. The middle plot is the measurement of the faulted phase current. The bottom plot shows the odd harmonics and off harmonics in solid and dash traces, respectively. The fault current is about 25 A. We do not see much off-harmonic activity from the fault, but the fault does generate a large change in odd-harmonic content of the station current. A high-impedance fault device successfully detected this fault.

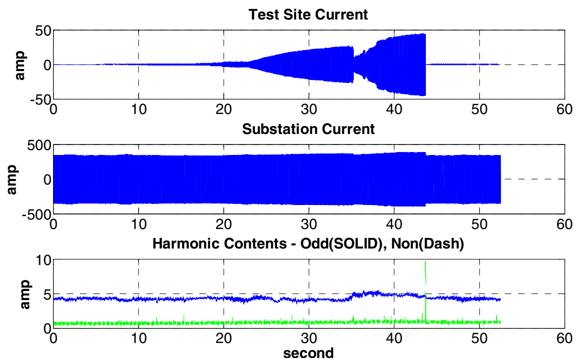


Fig. 10. A gravel fault from Test A(1)

Fig. 10 shows a gravel test from Test A(1). As we pointed out before, the weather, ground, and test conditions are very similar to the fault test in Fig. 9. The fault current is about 31 A, larger than that of Fig. 9. However, the same fault detection device failed to pick up this fault. From the bottom plot of Fig. 10, we see insignificant changes in odd harmonics and off harmonics generated by the fault.

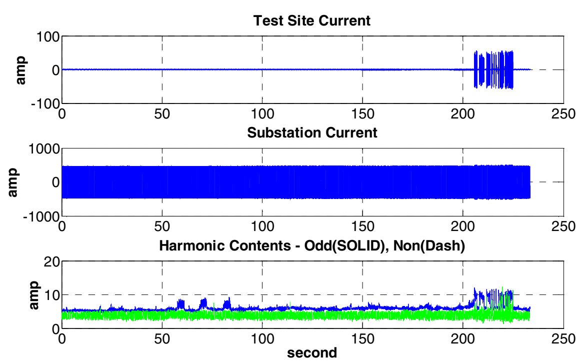


Fig. 11. A tree fault from Test E(1)

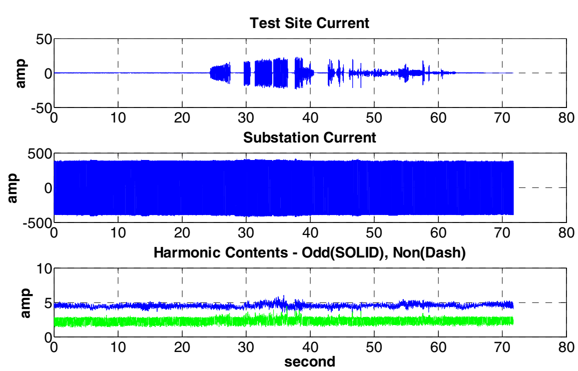


Fig. 12. A tree fault from Test A(1)

The second example is for tree faults. Fig. 11 and Fig. 12 show two downed conductor faults on a tree branch, from Test E(1) and Test A(1) respectively. The fault of Test E(1) generated enough off-harmonic content at the substation so that the fault detection device picked up the fault easily. The fault from Test A(1) however, did not have enough off-harmonic content, so the device failed to detect the fault.

These examples illustrate that faults occurring on the same feeder, at the same location, and on the same ground surfaces have subtle differences in the harmonic contents of fault currents and result in quite different fault detection outcomes. Similar previously undetected faults could be detected at a different time.

Finally, the fault detection device has demonstrated a high probability in detecting such earth faults as in Tests A(2) and E(2). However, the same device did not detect as many earth faults from Tests A(1) and E(1). Fig. 13 shows one of the earth faults from Test E(2) that the device detected. The fault current is about 70 A. We see that there is a large harmonic content in the substation current. Fig. 14 shows one of the earth faults from Test A(1). From the bottom plot, we see that the fault did not produce enough harmonics for the detection device. The comparison of these two tests illustrates that for similar earth faults that are about 10 miles apart, the composition of soil dictates the outcome of the fault current and, therefore, the detection results. It is generally true that a detection device has a greater chance of detecting a high-impedance fault that is closer to a substation because of less attenuation of high-frequency fault signatures by VAR-compensation capacitors of distribution systems.

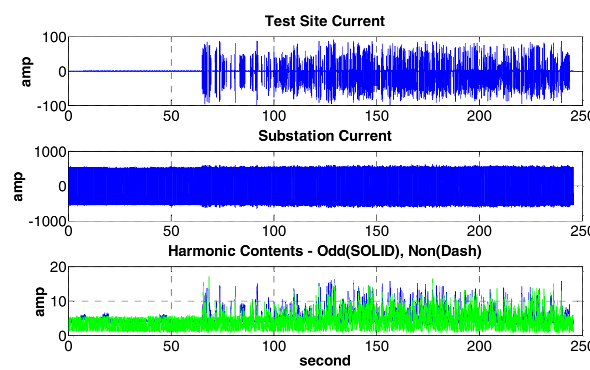


Fig. 13. Fault current of an earth fault from Test E(2)

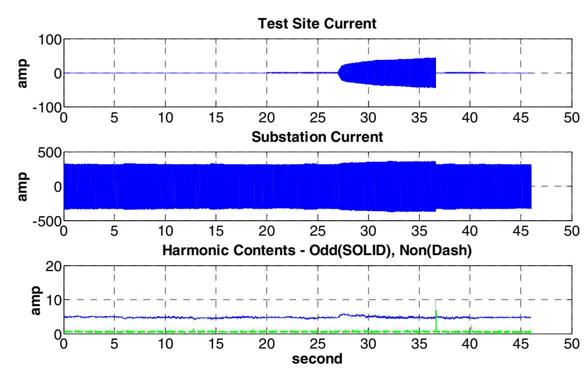


Fig. 14. Fault current of an earth fault from Test A(1)

Given the random nature of high-impedance faults and their detection, using a single value for detection rate to describe the performance of a fault detection device can be very limited and sometimes misleading. For any given number, we want to know immediately under what kind of ground surfaces, surface conditions, and voltage levels the number is derived.

From field test experiences, we believe that it is better to use a statistical way to describe the performance of a high-impedance fault detection device. For each ground surface type, we have a good idea about the likelihood of a fault being detected when a conductor falls on it, although we have seen previously that differences can exist from different fault occurrences. Fig. 15 shows a statistical method of describing a high-impedance fault detection device.

Fig. 15. Statistical description of high-impedance fault detection device

VII. Conclusion

High-impedance fault detection is a perplexing issue facing utilities. A downed conductor-related high-impedance fault is a great public hazard and must be corrected quickly to prevent loss of life and property damage.

High-impedance fault detection depends on the system grounding scheme. For small-current grounding, the fault detection is relatively easy because the standing unbalance comes only from line construction asymmetry and phase CT errors. This unbalance is normally quite small, and today's microprocessor relays can be sensitive enough to detect most high-impedance faults.

For large-current grounded systems, where system standing unbalance is high or unpredictable from single-phase loads, the detection of high-impedance faults is more challenging. Because the high-impedance fault current is less than the standing unbalance, we must explore quantities other than the current fundamental magnitude or RMS value for detection purposes. Most high-impedance fault detection devices today use the harmonic contents of a fault current together with many available techniques such as artificial intelligence.

A substation-based device cannot detect all high-impedance faults. Downed conductors on asphalt and dry sand produce no fault currents and therefore cannot be detected by substation-based devices.

Given the complex nature of a high-impedance fault, it is impossible to simulate faithfully all aspects of a high-impedance fault. Field-staged fault tests are a way to study these faults and validate the performance of a detection device.

Many field fault tests show that you cannot get the same fault twice. The high-impedance fault is a dynamic process. The surface electrical condition changes as moisture evaporates from the heat of arcs, as a conductor burns off and moves around, and as ground material fuses into silicon composites. We may be able to detect a fault at one moment that we cannot detect later. Because of seasonal changes and ground composition changes, a fault test today may not produce the same current and arc signatures as a previous fault test at the same location.

People have been using a single number called detection rate to describe the performance of a detection device. It may be reasonable to use a particular probability number to describe the performance for downed conductor faults on a given ground surface. The use of a single detection rate without discriminating ground surface types can be misleading. If all faults come from downed conductors on asphalt, the detection rate will undoubtedly be zero.

It is therefore more accurate to describe the performance of a detection device statistically according to each type of ground surface.

VIII. References

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IX. Biographies

Daqing Hou received his BSEE and MSEE degrees at the Northeast University, China, in 1981 and 1984, respectively. He received his Ph.D. in Electrical and Computer Engineering at Washington State University in 1991. Since 1990, he has been with Schweitzer Engineering Laboratories, Inc., Pullman, Washington, USA, where he has held numerous positions including development engineer, application engineer, and R&D manager. He is currently a principal research engineer. His work includes system modeling, simulation, and signal processing for power systems and digital protective relays. His research interests include multivariable linear systems, system identification, and signal processing. He holds multiple patents and has authored or coauthored many technical papers. He is a Senior Member of IEEE.

Workpaper Title:

High Impedance Relays Workpaper

WP SCE-04 Vol. 05 Part 3

High-Impedance Relays (Hi-Z) Workpaper

A	B	C	D	E	F	G	H
1	**CAPITAL**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**
2	**Engineering Design, Material, Protection Execution, Construction and Apparatus Support**	**$ -**	**$ -**	**$ 1,250,000**	**$ 1,250,000**	**$ 1,250,000**	**$ 1,250,000**
3	# of Locations			20	20	20	20
4							
5	**Explanations and Assumptions -**						
6	Cost per Location (includes engineering, necessary infrastructure upgrades, deployment and testing of the Hi-Z scheme).	$ 62,500					
7	Deploying the scheme on existing infrastructure may require upgrades such as controllers, voltage sensors and pole replacements in order to succesfully deploy the scheme.						
8	Total Capital cost per year calculated as (Cost per Location * # of Locations).						
9	The forecast incorporates accounting adjustments that include certain changes made to SCE's employee compensation program. Please refer to SCE-06, Vol. 04.						
10	Net amount of total adjustments	$ -	$ -	$ (59,664)	$ (58,591)	$ (61,265)	$ (59,139)
11							
12							
13	**O&M**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**
14	**Labor required to investigate and gather event data**	**$ 103,600**	**$ 103,600**	**$ 145,600**	**$ 187,600**	**$ 229,600**	**$ 271,600**
15	# of Installed Locations	37	37	52	67	82	97
16							
17	**Explanations and Assumptions -**						
18	Labor cost for 1/2 day crew: Cost of event investigation and data gathering is estimated to require half of a crew day. Cost per full crew day is estimated at $7,000 so the cost of a 1/2 day crew is $3,500.	$ 3,500					
19	Expected Event Frequency: Assume that 80% of the installed units to have one event per year requiring labor investigation.	0.8					
20	Install base as of YE 2022 is 37 units.						
21	Increase in cost for years 2025 through 2028 is based on an increase in the install base per year starting in 2025.						
22	Total O&M cost per year calculated as (# Installed Locations * Expected Event Frequency * Labor cost for 1/2 day crew)						
23	The forecast incorporates accounting adjustments that include certain changes made to SCE's employee compensation program. Please refer to SCE-06, Vol. 04.						
24	Net amount of total adjustments	$ (111)	$ 1,980	$ 803	$ (2,633)	$ (8,496)	$ (16,308)

Workpaper Title:

Capital Detail for High-Impedance Relays

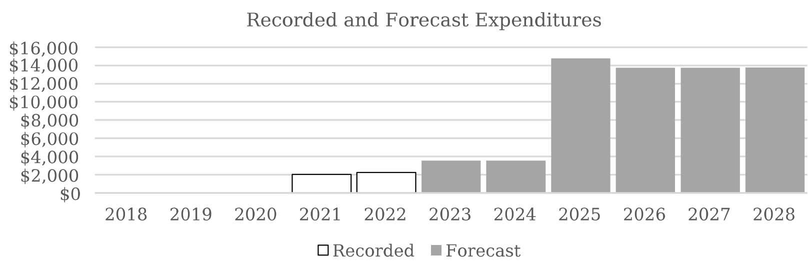
WP SCE-04 Vol. 05 Part 3

Southern California Edison - Capital Workpapers
Capital Workpapers Summary
SUMMARY BY GRC Volume
(Nominal $000)

Exhibit: SCE-04 Resiliency
Volume: 5 Pt. 3 - Wildfire Management

	Recorded Capital Expenditures					Forecast Capital Expenditures					
Description	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Recorded and Forecast Expenditures				2,015	2,243	3,528	3,522	14,758	13,741	13,742	13,773
Total Expenditures					**4,258**						**63,063**

Due to rounding, totals may not tie to individual items.



	Forecast Capital Expenditures						
GRC Activity	2023	2024	2025	2026	2027	2028	6 yr Total
Alternative Technologies	3,528	3,522	14,758	13,741	13,742	13,773	63,063
GRC Total	3,528	3,522	14,758	13,741	13,742	13,773	63,063

Southern California Edison
2025 GRC Capital Workpapers

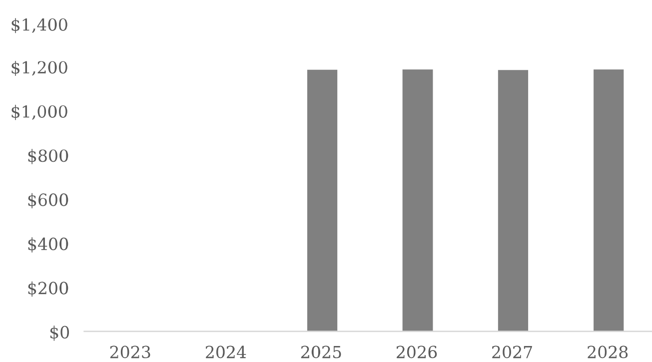
Exhibit:	SCE-04 Resiliency
Volume:	5 Pt. 3 - Wildfire Management
Business Plan Group:	Resiliency
Business Plan Element:	Wildfire Management
GRC Activity:	Alternative Technologies
1. Witness:	Andrew Swisher
2. Asset type:	DS-SUB
3. In-Service date:	12\1\9999
4. RO Model ID:	985
5. Pin:	8224
6. CWBS Element:	CETPDWMST822400
CWBS Description:	High Impedance Relay Evalutaion
7. SRIIM Eligible:	No

Cost Estimates - Nominal ($000)

2025 GRC - Capital Expenditures Forecast

Year	2023	2024	2025	2026	2027	2028	2023 - 2028 Total
SCE$	0	0	1,190	1,191	1,189	1,191	4,761

Due to rounding, totals may not tie to individual items.



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2025 General Rate Case

A. 23-05-

Workpapers

SCE-04 Resiliency
Volume 5 Pt. 3 - Wildfire Management
Organizational Support

May 2023

2025 GRC Summary

(Constant 2022 $000)

Beginning of Workpapers for:	
Exhibit:	SCE-04 Resiliency
Volume:	5 Pt. 3 - Wildfire Management
Business Planning Element:	Wildfire Management
Activity:	Organizational Support
Witness:	Kristi Gardner

Cost Type	Recorded/Adj. 2022	Forecast 2025
Labor	162	0
Non-Labor	8,019	3,173
Other	0	0
Total	8,181	3,173

Due to rounding, totals may not tie to individual items.

Description of Activity:
This activity includes the labor and contract costs associated with change management support for EOI, PSPS, and other wildfire management activities.

Forecast Methods - Summary of Results of Methods Studied

(Constant 2022 $000)

Exhibit: SCE-04 Resiliency
Volume: 5 Pt. 3 - Wildfire Management
Business Planning Element: Wildfire Management
Activity: Organizational Support
Witness: Kristi Gardner

Cost Type	Recorded/Adj.				
	2018	2019	2020	2021	2022
Labor	5	616	686	221	162
Non-Labor	69	48,896	40,000	11,883	8,019
Other	0	0	0	0	0
Total	**74**	**49,512**	**40,687**	**12,104**	**8,181**

Cost Type	Results of Linear Trending					
	3 Years: 2020 - 2022		4 Years: 2019 - 2022		5 Years: 2018 - 2022	
	$	r2*	$	r2*	$	r2*
Labor	(692)	0.83	(401)	0.77	298	0.00
Non-Labor	(43,996)	0.84	(40,637)	0.92	11,217	0.02
Other	0	0.00	0	0.00	0	0.00
Total	**(44,687)**	**N/A**	**(41,038)**	**N/A**	**11,514**	**N/A**

Cost Type	Results of Averaging							
	2 Years:		3 Years:		4 Years:		5 Years:	
	2021 - 2022	sd**	2020 - 2022	sd**	2019 - 2022	sd**	2018 - 2022	sd**
Labor	192	29	356	234	421	232	338	266
Non-Labor	9,951	1,932	19,967	14,253	27,200	17,586	21,773	19,110
Other	0	0	0	0	0	0	0	0
Total	**10,143**	**N/A**	**20,324**	**N/A**	**27,621**	**N/A**	**22,112**	**N/A**

Cost Type	Last Recorded Year		
	2023	2024	2025
Labor	162	162	162
Non-Labor	8,019	8,019	8,019
Other	0	0	0
Total	**8,181**	**8,181**	**8,181**

Cost Type	Itemized Forecast		
	2023	2024	2025
Labor	0	0	0
Non-Labor	4,498	3,934	3,173
Other	0	0	0
Total	**4,498**	**3,934**	**3,173**

** r2 = R Squared (Based on recorded years data)*

*** sd = standard deviation (Based on recorded years data)*

2025 GRC Selected Forecast Method

(Constant 2022 $000)

Exhibit:	SCE-04 Resiliency
Volume:	5 Pt. 3 - Wildfire Management
Business Planning Element:	Wildfire Management
Activity:	Organizational Support
Witness:	Kristi Gardner

Cost Type	Recorded/Adj.					Forecast			Selected Forecast		TY Forecast Incr/(Decr) from 2022
	2018	2019	2020	2021	2022	2023	2024	2025	Method	($000)	
Labor	5	616	686	221	162				Itemized		
Non-Labor	69	48,896	40,000	11,883	8,019	4,498	3,934	3,173	Itemized	3,173	(4,846)
Other											
Total	**74**	**49,512**	**40,687**	**12,104**	**8,181**	**4,498**	**3,934**	**3,173**		**3,173**	**(4,846)**

Due to rounding, totals may not tie to individual items.

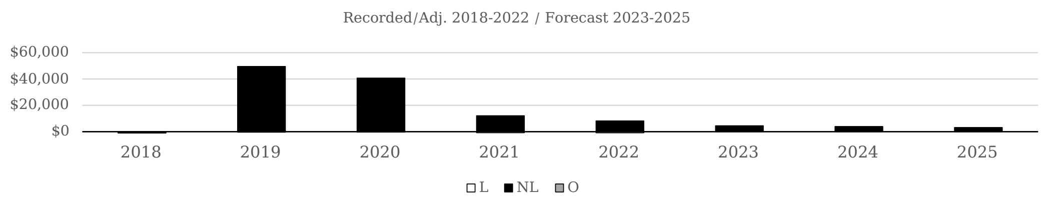
Analysis of Forecasting Methods
Itemized Forecast: Itemized Forecast Method

Other Forecast Methods not Selected
Last Recorded Year: In D.89-12-057, and subsequently in D.04-07-022, the CPUC stated that if recorded expenses have been relatively stable for three or more years, the last recorded year is an appropriate base estimate. For this activity the Last Recorded Year method does not account for the variables discussed in testimony to determine the 2025 Test Year forecast. Therefore, the Last Recorded Year method is not appropriate.
Linear Trending: In D.89-12-057, and subsequently in D.04-07-022, the CPUC stated that if recorded expenses have been relatively stable for three or more years, the last recorded year is an appropriate base estimate. For this activity the Linear Trending method does not account for the variables discussed in testimony to determine the 2025 Test Year forecast. Therefore, the Linear Trending method is not appropriate.
Averaging: In D.89-12-057, and subsequently in D.04-07-022, the CPUC stated that if recorded expenses have significant fluctuations from year to year, or expenses are influenced by external forces beyond the utility’s control, an average of recorded-expenses is appropriate. For this activity the Averaging method does not account for the variables discussed in testimony to determine the 2025 Test Year forecast. Therefore, the Averaging method is not appropriate.

2025 GRC Year Over Year Variance

(Constant 2022 $000)

Exhibit:	SCE-04 Resiliency
Volume:	5 Pt. 3 - Wildfire Management
Business Planning Element:	Wildfire Management
Activity:	Organizational Support
Witness:	Kristi Gardner



Cost Type		Recorded/Adj.					Forecast		
		2018	2019	2020	2021	2022	2023	2024	2025
Recorded / Forecast	Labor	5	616	686	221	162	0	0	0
	Non-Labor	69	48,896	40,000	11,883	8,019	4,498	3,934	3,173
	Other	0	0	0	0	0	0	0	0
	Total	**74**	**49,512**	**40,687**	**12,104**	**8,181**	**4,498**	**3,934**	**3,173**

		2019	2020	2021	2022	2023	2024	2025
Labor	Prior Year Total	5	616	686	221	162	0	0
	Change	611	70	(465)	(59)	(162)	0	0
	Total	**616**	**686**	**221**	**162**	**0**	**0**	**0**
Non-Labor	Prior Year Total	69	48,896	40,000	11,883	8,019	4,498	3,934
	Change	48,826	(8,895)	(28,117)	(3,864)	(3,520)	(564)	(761)
	Total	**48,896**	**40,000**	**11,883**	**8,019**	**4,498**	**3,934**	**3,173**
Other	Prior Year Total	0	0	0	0	0	0	0
	Change	0	0	0	0	0	0	0
	Total	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Total Change	Prior Year Total	74	49,512	40,687	12,104	8,181	4,498	3,934
	Change	49,437	(8,825)	(28,582)	(3,923)	(3,683)	(564)	(761)
	Total	**49,512**	**40,687**	**12,104**	**8,181**	**4,498**	**3,934**	**3,173**

Due to rounding, totals may not tie to individual items.

2025 GRC Forecast Commentary

(Constant 2022 $000)

Exhibit:	SCE-04 Resiliency
Volume:	5 Pt. 3 - Wildfire Management
Business Planning Element:	Wildfire Management
Activity:	Organizational Support
Witness:	Kristi Gardner

Summary of Changes: See Testimony

Cost Type		Recorded/Adj.					Forecast		
		2018	2019	2020	2021	2022	2023	2024	2025
Recorded / Forecast	Labor	5	616	686	221	162	0	0	0
	Non-Labor	69	48,896	40,000	11,883	8,019	4,498	3,934	3,173
	Other	0	0	0	0	0	0	0	0
	Total	74	49,512	40,687	12,104	8,181	4,498	3,934	3,173

Due to rounding, totals may not tie to individual items.

Recorded (2018-2022)
See Testimony

Forecast (2023-2025)
See Testimony

Workpaper Title:

Generation

WP SCE-04 Vol. 05 Part 3

I. GENERATION

A. Ground

For generation assets, risk-informed, asset-based ground inspections are performed within SCE's HFRA. For 2020 and 2021, 268 inspections (31 from AOCs) and 232 inspections (56 from AOCs) were completed, respectively. In 2022, 222 inspections were completed with 37 of the inspections from AOCs. For 2023 and 2024, SCE plans to complete approximately 190 and 200 inspections, respectively. SCE plans to inspect approximately 190 generation assets in 2025 within HFRA.

B. Areas of Concern (AOCs)

Legacy facilities were included as part of the AOCs for assets located within those identified AOCs. In 2020, legacy facility assets were located within 2 of the AOCs. SCE conducted 20 repeat inspections and expedited 11 new inspections originally scheduled for 2021. SCE also expedited the completion of 5 P2s and 13 P3s.

C. Remediations

In 2020, SCE issued 80 notifications based on the inspections of IN-5. Of those notifications, 15 were priority P2 and 65 priority P3. There were no priority P1 conditions identified during the IN-5 Inspections. SCE incurred $157,042 O&M costs for the remediations performed in 2020. Approximately 88% of the notifications were related to vegetation categories such as brushing, weed eat/mow abatement, debris management/removal and tree trim/limb. Notifications that involved trees too close to distribution lines were completed by SCE's vegetation management group due to the unique qualifications required for clearing near powerlines. Asset issues were not a common finding and typically were cable/conductor repairs or removal.

In 2021, SCE continued the IN-5 Inspections program and issued 42 notifications. Of those notifications, 21 were priority P2 and 21 were priority P3. There were no priority P1 conditions identified during the IN-5 Inspections. SCE incurred $62,483 O&M costs for the remediations performed in 2021. Approximately 93% of the notifications were related to vegetation categories such as brushing, weed eat/mow abatement, debris management/removal and tree trim/limb. Notifications that involved trees too close to distribution lines were completed by SCE's vegetation management group due to the unique qualifications required for clearing near powerlines. Asset issue categories were disconnected cable/conduit, replace cable/conduit, and repair cable/conduit.

In 2022, SCE resumed the IN-5 Inspections program generating 8 priority P2 notifications and 17 priority P3 notifications for a total of 25 inspection notifications. There were no priority P1 notifications identified during this cycle of the IN-5 inspections. SCE incurred $53,055 in O&M costs with respect to inspections and remediations. Three notifications were related to dead trees posing a risk to infrastructure and completed by SCE's vegetation management group. The remaining notifications were related to tree trimming and weed abatement.

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2025 General Rate Case

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Workpapers

SCE-04 Resiliency
Volume 5 Pt. 3 - Wildfire Management
High Fire Risk Inspections and Remediations

May 2023

2025 GRC Summary

(Constant 2022 $000)

Beginning of Workpapers for:

Exhibit:	SCE-04 Resiliency
Volume:	5 Pt. 3 - Wildfire Management
Business Planning Element:	Wildfire Management
Activity:	High Fire Risk Inspections and Remediations
Witness:	Ray Fugere

Cost Type	Recorded/Adj. 2022	Forecast 2025
Labor	24,183	28,721
Non-Labor	75,983	105,761
Other	0	0
Total	**100,166**	**134,482**

Due to rounding, totals may not tie to individual items.

Description of Activity:
The costs associated with this program includes the various inspection programs (e.g., HFRA 360 for distribution consisting of both ground and aerial, transmission aerial, areas of concern, etc.) as well as the result remediations when notifications are identified in the field.

Forecast Methods - Summary of Results of Methods Studied

(Constant 2022 $000)

Exhibit:	SCE-04 Resiliency
Volume:	5 Pt. 3 - Wildfire Management
Business Planning Element:	Wildfire Management
Activity:	High Fire Risk Inspections and Remediations
Witness:	Ray Fugere

Cost Type	Recorded/Adj.				
	2018	2019	2020	2021	2022
Labor	5,025	55,652	26,749	27,021	24,183
Non-Labor	412	311,802	177,696	99,878	75,983
Other	0	0	0	0	0
Total	**5,437**	**367,453**	**204,445**	**126,899**	**100,166**

Cost Type	Results of Linear Trending					
	3 Years: 2020 - 2022		4 Years: 2019 - 2022		5 Years: 2018 - 2022	
	$	r2*	$	r2*	$	r2*
Labor	20,851	0.67	(8,960)	0.67	32,568	0.01
Non-Labor	(85,573)	0.91	(187,034)	0.91	102,763	0.01
Other	0	0.00	0	0.00	0	0.00
Total	**(64,722)**	**N/A**	**(195,993)**	**N/A**	**135,332**	**N/A**

Cost Type	Results of Averaging							
	2 Years:		3 Years:		4 Years:		5 Years:	
	2021 - 2022	sd**	2020 - 2022	sd**	2019 - 2022	sd**	2018 - 2022	sd**
Labor	25,602	1,419	25,984	1,279	33,401	12,894	27,726	16,181
Non-Labor	87,930	11,948	117,852	43,426	166,340	92,019	133,154	105,731
Other	0	0	0	0	0	0	0	0
Total	**113,532**	**N/A**	**143,837**	**N/A**	**199,741**	**N/A**	**160,880**	**N/A**

Cost Type	Last Recorded Year		
	2023	2024	2025
Labor	24,183	24,183	24,183
Non-Labor	75,983	75,983	75,983
Other	0	0	0
Total	**100,166**	**100,166**	**100,166**

Cost Type	Itemized Forecast		
	2023	2024	2025
Labor	27,465	27,985	28,721
Non-Labor	101,915	104,089	105,761
Other	0	0	0
Total	**129,380**	**132,075**	**134,482**

** r2 = R Squared (Based on recorded years data)*

*** sd = standard deviation (Based on recorded years data)*

2025 GRC Selected Forecast Method

(Constant 2022 $000)

Exhibit:	SCE-04 Resiliency
Volume:	5 Pt. 3 - Wildfire Management
Business Planning Element:	Wildfire Management
Activity:	High Fire Risk Inspections and Remediations
Witness:	Ray Fugere

Cost Type	Recorded/Adj.					Forecast			Selected Forecast		TY Forecast Incr/(Decr) from 2022
	2018	2019	2020	2021	2022	2023	2024	2025	Method	($000)	
Labor	5,025	55,652	26,749	27,021	24,183	27,465	27,985	28,721	Itemized	28,721	4,538
Non-Labor	412	311,802	177,696	99,878	75,983	101,915	104,089	105,761	Itemized	105,761	29,778
Other											
Total	**5,437**	**367,453**	**204,445**	**126,899**	**100,166**	**129,380**	**132,075**	**134,482**		**134,482**	**34,316**

Due to rounding, totals may not tie to individual items.

Analysis of Forecasting Methods

Itemized Forecast:
Itemized Forecast Method

Other Forecast Methods not Selected

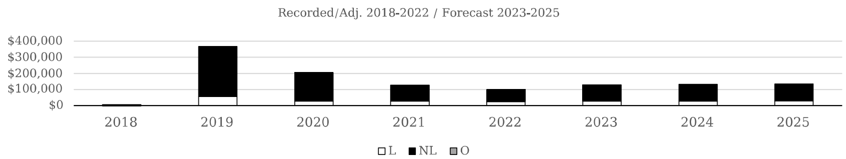
Last Recorded Year:
In D.89-12-057, and subsequently in D.04-07-022, the CPUC stated that if recorded expenses have been relatively stable for three or more years, the last recorded year is an appropriate base estimate. For this activity the Last Recorded Year method does not account for the variables discussed in testimony to determine the 2025 Test Year forecast. Therefore, the Last Recorded Year method is not appropriate.

Linear Trending:
In D.89-12-057, and subsequently in D.04-07-022, the CPUC stated that if recorded expenses have been relatively stable for three or more years, the last recorded year is an appropriate base estimate. For this activity the Linear Trending method does not account for the variables discussed in testimony to determine the 2025 Test Year forecast. Therefore, the Linear Trending method is not appropriate.

Averaging:
In D.89-12-057, and subsequently in D.04-07-022, the CPUC stated that if recorded expenses have significant fluctuations from year to year, or expenses are influenced by external forces beyond the utility's control, an average of recorded-expenses is appropriate. For this activity the Averaging method does not account for the variables discussed in testimony to determine the 2025 Test Year forecast. Therefore, the Averaging method is not appropriate.

2025 GRC Year Over Year Variance
(Constant 2022 $000)

Exhibit:	SCE-04 Resiliency
Volume:	5 Pt. 3 - Wildfire Management
Business Planning Element:	Wildfire Management
Activity:	High Fire Risk Inspections and Remediations
Witness:	Ray Fugere



Cost Type		Recorded/Adj.					Forecast		
		2018	2019	2020	2021	2022	2023	2024	2025
Recorded / Forecast	Labor	5,025	55,652	26,749	27,021	24,183	27,465	27,985	28,721
	Non-Labor	412	311,802	177,696	99,878	75,983	101,915	104,089	105,761
	Other	0	0	0	0	0	0	0	0
	Total	**5,437**	**367,453**	**204,445**	**126,899**	**100,166**	**129,380**	**132,075**	**134,482**

Labor	Prior Year Total	5,025	55,652	26,749	27,021	24,183	27,465	27,985
	Change	50,626	(28,902)	272	(2,838)	3,282	521	735
	Total	**55,652**	**26,749**	**27,021**	**24,183**	**27,465**	**27,985**	**28,721**

Non-Labor	Prior Year Total	412	311,802	177,696	99,878	75,983	101,915	104,089
	Change	311,390	(134,106)	(77,818)	(23,895)	25,932	2,174	1,671
	Total	**311,802**	**177,696**	**99,878**	**75,983**	**101,915**	**104,089**	**105,761**

Other	Prior Year Total	0	0	0	0	0	0	0
	Change	0	0	0	0	0	0	0
	Total	**0**	**0**	**0**	**0**	**0**	**0**	**0**

Total Change	Prior Year Total	5,437	367,453	204,445	126,899	100,166	129,380	132,075
	Change	362,016	(163,008)	(77,546)	(26,733)	29,214	2,695	2,407
	Total	**367,453**	**204,445**	**126,899**	**100,166**	**129,380**	**132,075**	**134,482**

Due to rounding, totals may not tie to individual items.

2025 GRC Forecast Commentary

(Constant 2022 $000)

Exhibit:	SCE-04 Resiliency
Volume:	5 Pt. 3 - Wildfire Management
Business Planning Element:	Wildfire Management
Activity:	High Fire Risk Inspections and Remediations
Witness:	Ray Fugere

Summary of Changes: See Testimony

Cost Type		Recorded/Adj.					Forecast		
		2018	2019	2020	2021	2022	2023	2024	2025
Recorded / Forecast	Labor	5,025	55,652	26,749	27,021	24,183	27,465	27,985	28,721
	Non-Labor	412	311,802	177,696	99,878	75,983	101,915	104,089	105,761
	Other	0	0	0	0	0	0	0	0
	Total	**5,437**	**367,453**	**204,445**	**126,899**	**100,166**	**129,380**	**132,075**	**134,482**

Due to rounding, totals may not tie to individual items.

Recorded (2018-2022)

See Testimony

Forecast (2023-2025)

See Testimony

(U 338-E)

2025 General Rate Case

A. 23-05-

Workpapers

SCE-04 Resiliency
Volume 5 Pt. 3 - Wildfire Management
Infrared Inspection Program

May 2023

2025 GRC Summary

(Constant 2022 $000)

Beginning of Workpapers for:

Exhibit:	SCE-04 Resiliency
Volume:	5 Pt. 3 - Wildfire Management
Business Planning Element:	Wildfire Management
Activity:	Infrared Inspection Program
Witness:	Ray Fugere

Cost Type	Recorded/Adj. 2022	Forecast 2025
Labor	89	50
Non-Labor	454	533
Other	0	0
Total	**543**	**583**

Due to rounding, totals may not tie to individual items.

Description of Activity:
This activity includes the costs associated with performing infrared inspections on High Fire Risk Area (HFRA) distribution circuits as well as infrared and corona inspections on transmission lines in HFRA.

Forecast Methods - Summary of Results of Methods Studied

(Constant 2022 $000)

Exhibit:	SCE-04 Resiliency
Volume:	5 Pt. 3 - Wildfire Management
Business Planning Element:	Wildfire Management
Activity:	Infrared Inspection Program
Witness:	Ray Fugere

Cost Type	Recorded/Adj.				
	2018	2019	2020	2021	2022
Labor	0	1	379	115	89
Non-Labor	0	0	1,049	517	454
Other	0	0	0	0	0
Total	**0**	**1**	**1,429**	**632**	**543**

Cost Type	Results of Linear Trending					
	3 Years: 2020 - 2022		4 Years: 2019 - 2022		5 Years: 2018 - 2022	
	$	r2*	$	r2*	$	r2*
Labor	(387)	0.82	146	0.00	262	0.09
Non-Labor	(517)	0.83	879	0.06	1,117	0.27
Other	0	0.00	0	0.00	0	0.00
Total	**(903)**	**N/A**	**1,025**	**N/A**	**1,380**	**N/A**

Cost Type	Results of Averaging							
	2 Years:		3 Years:		4 Years:		5 Years:	
	2021 - 2022	sd**	2020 - 2022	sd**	2019 - 2022	sd**	2018 - 2022	sd**
Labor	102	13	194	131	146	141	117	139
Non-Labor	486	32	674	267	505	372	404	389
Other	0	0	0	0	0	0	0	0
Total	**588**	**N/A**	**868**	**N/A**	**651**	**N/A**	**521**	**N/A**

Cost Type	Last Recorded Year		
	2023	2024	2025
Labor	89	89	89
Non-Labor	454	454	454
Other	0	0	0
Total	**543**	**543**	**543**

Cost Type	Itemized Forecast		
	2023	2024	2025
Labor	52	51	50
Non-Labor	625	530	533
Other	0	0	0
Total	**676**	**581**	**583**

** r2 = R Squared (Based on recorded years data)*

*** sd = standard deviation (Based on recorded years data)*

2025 GRC Selected Forecast Method

(Constant 2022 $000)

Exhibit:	SCE-04 Resiliency
Volume:	5 Pt. 3 - Wildfire Management
Business Planning Element:	Wildfire Management
Activity:	Infrared Inspection Program
Witness:	Ray Fugere

Cost Type	Recorded/Adj.					Forecast			Selected Forecast		TY Forecast Incr/(Decr) from 2022
	2018	2019	2020	2021	2022	2023	2024	2025	Method	($000)	
Labor	0	1	379	115	89	52	51	50	Itemized	50	(39)
Non-Labor		0	1,049	517	454	625	530	533	Itemized	533	79
Other											
Total	**0**	**1**	**1,429**	**632**	**543**	**676**	**581**	**583**		**583**	**40**

Due to rounding, totals may not tie to individual items.

Analysis of Forecasting Methods
Itemized Forecast: Itemized Forecast Method

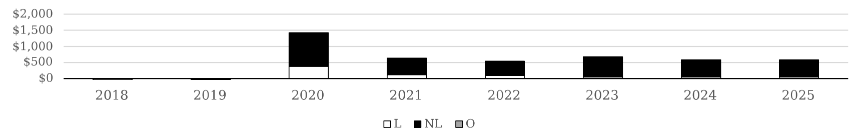
Other Forecast Methods not Selected
Last Recorded Year: In D.89-12-057, and subsequently in D.04-07-022, the CPUC stated that if recorded expenses have been relatively stable for three or more years, the last recorded year is an appropriate base estimate. For this activity the Last Recorded Year method does not account for the variables discussed in testimony to determine the 2025 Test Year forecast. Therefore, the Last Recorded Year method is not appropriate.
Linear Trending: In D.89-12-057, and subsequently in D.04-07-022, the CPUC stated that if recorded expenses have been relatively stable for three or more years, the last recorded year is an appropriate base estimate. For this activity the Linear Trending method does not account for the variables discussed in testimony to determine the 2025 Test Year forecast. Therefore, the Linear Trending method is not appropriate.
Averaging: In D.89-12-057, and subsequently in D.04-07-022, the CPUC stated that if recorded expenses have significant fluctuations from year to year, or expenses are influenced by external forces beyond the utility's control, an average of recorded-expenses is appropriate. For this activity the Averaging method does not account for the variables discussed in testimony to determine the 2025 Test Year forecast. Therefore, the Averaging method is not appropriate.

2025 GRC Year Over Year Variance

(Constant 2022 $000)

Exhibit:	SCE-04 Resiliency
Volume:	5 Pt. 3 - Wildfire Management
Business Planning Element:	Wildfire Management
Activity:	Infrared Inspection Program
Witness:	Ray Fugere

Recorded/Adj. 2018-2022 / Forecast 2023-2025



Cost Type		Recorded/Adj.					Forecast		
		2018	2019	2020	2021	2022	2023	2024	2025
Recorded / Forecast	Labor	0	1	379	115	89	52	51	50
	Non-Labor	0	0	1,049	517	454	625	530	533
	Other	0	0	0	0	0	0	0	0
	Total	**0**	**1**	**1,429**	**632**	**543**	**676**	**581**	**583**

		2019	2020	2021	2022	2023	2024	2025
Labor	Prior Year Total	0	1	379	115	89	52	51
	Change	0	379	(265)	(26)	(37)	(0)	(1)
	Total	**1**	**379**	**115**	**89**	**52**	**51**	**50**
Non-Labor	Prior Year Total	0	0	1,049	517	454	625	530
	Change	0	1,049	(532)	(63)	171	(95)	2
	Total	**0**	**1,049**	**517**	**454**	**625**	**530**	**533**
Other	Prior Year Total	0	0	0	0	0	0	0
	Change	0	0	0	0	0	0	0
	Total	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Total Change	Prior Year Total	0	1	1,429	632	543	676	581
	Change	0	1,428	(797)	(89)	133	(95)	2
	Total	**1**	**1,429**	**632**	**543**	**676**	**581**	**583**

Due to rounding, totals may not tie to individual items.

2025 GRC Forecast Commentary

(Constant 2022 $000)

Exhibit:	SCE-04 Resiliency
Volume:	5 Pt. 3 - Wildfire Management
Business Planning Element:	Wildfire Management
Activity:	Infrared Inspection Program
Witness:	Ray Fugere

Summary of Changes: See Testimony

Cost Type		Recorded/Adj.					Forecast		
		2018	2019	2020	2021	2022	2023	2024	2025
Recorded / Forecast	Labor	0	1	379	115	89	52	51	50
	Non-Labor	0	0	1,049	517	454	625	530	533
	Other	0	0	0	0	0	0	0	0
	Total	**0**	**1**	**1,429**	**632**	**543**	**676**	**581**	**583**

Due to rounding, totals may not tie to individual items.

Recorded (2018-2022)

See Testimony

Forecast (2023-2025)

See Testimony

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Workpapers

SCE-04 Resiliency
Volume 5 Pt. 3 - Wildfire Management
Wildfire Mitigation and Vegetation Management Technology Solutions

May 2023

2025 GRC Summary

(Constant 2022 $000)

Beginning of Workpapers for:

Exhibit:	SCE-04 Resiliency
Volume:	5 Pt. 3 - Wildfire Management
Business Planning Element:	Wildfire Management
Activity:	Wildfire Mitigation and Vegetation Management Technology Solutions
Witness:	Jeff Gooding

Cost Type	Recorded/Adj. 2022	Forecast 2025
Labor	162	0
Non-Labor	5,487	6,741
Other	0	0
Total	**5,648**	**6,741**

Due to rounding, totals may not tie to individual items.

Description of Activity:
Technology solutions supporting Vegetation Management and various Wildfire Mitigation programs.

Forecast Methods - Summary of Results of Methods Studied

(Constant 2022 $000)

Exhibit:	SCE-04 Resiliency
Volume:	5 Pt. 3 - Wildfire Management
Business Planning Element:	Wildfire Management
Activity:	Wildfire Mitigation and Vegetation Management Technology Solutions
Witness:	Jeff Gooding

Cost Type	Recorded/Adj.				
	2018	2019	2020	2021	2022
Labor	0	1	108	168	162
Non-Labor	0	2,184	2,768	3,743	5,487
Other	0	0	0	0	0
Total	**0**	**2,185**	**2,876**	**3,912**	**5,648**

Cost Type	Results of Linear Trending					
	3 Years: 2020 - 2022		4 Years: 2019 - 2022		5 Years: 2018 - 2022	
	$	r2*	$	r2*	$	r2*
Labor	254	0.66	354	0.82	333	0.87
Non-Labor	9,436	0.97	8,443	0.95	9,103	0.96
Other	0	0.00	0	0.00	0	0.00
Total	**9,690**	**N/A**	**8,797**	**N/A**	**9,436**	**N/A**

Cost Type	Results of Averaging							
	2 Years:		3 Years:		4 Years:		5 Years:	
	2021 - 2022	sd**	2020 - 2022	sd**	2019 - 2022	sd**	2018 - 2022	sd**
Labor	165	3	146	27	110	67	88	74
Non-Labor	4,615	872	3,999	1,124	3,546	1,251	2,836	1,807
Other	0	0	0	0	0	0	0	0
Total	**4,780**	**N/A**	**4,145**	**N/A**	**3,655**	**N/A**	**2,924**	**N/A**

Cost Type	Last Recorded Year		
	2023	2024	2025
Labor	162	162	162
Non-Labor	5,487	5,487	5,487
Other	0	0	0
Total	**5,648**	**5,648**	**5,648**

Cost Type	Itemized Forecast		
	2023	2024	2025
Labor	0	0	0
Non-Labor	8,421	7,733	6,741
Other	0	0	0
Total	**8,421**	**7,733**	**6,741**

** r2 = R Squared (Based on recorded years data)*

*** sd = standard deviation (Based on recorded years data)*

2025 GRC Selected Forecast Method

(Constant 2022 $000)

Exhibit:	SCE-04 Resiliency
Volume:	5 Pt. 3 - Wildfire Management
Business Planning Element:	Wildfire Management
Activity:	Wildfire Mitigation and Vegetation Management Technology Solutions
Witness:	Jeff Gooding

Cost Type	Recorded/Adj.					Forecast			Selected Forecast		TY Forecast Incr/(Decr) from 2022
	2018	2019	2020	2021	2022	2023	2024	2025	Method	($000)	
Labor		1	108	168	162				Itemized		
Non-Labor		2,184	2,768	3,743	5,487	8,421	7,733	6,741	Itemized	6,741	1,254
Other											
Total	0	2,185	2,876	3,912	5,648	8,421	7,733	6,741		6,741	1,254

Due to rounding, totals may not tie to individual items.

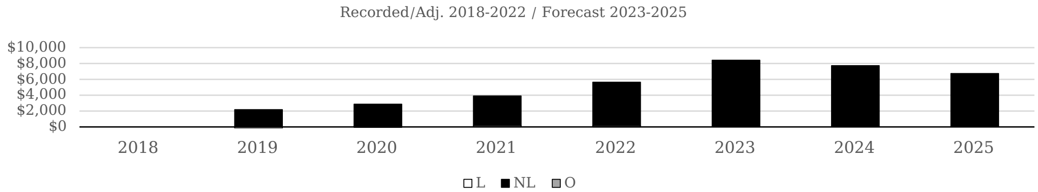
Analysis of Forecasting Methods
Itemized Forecast: Itemized Forecast Method

Other Forecast Methods not Selected
Last Recorded Year: In D.89-12-057, and subsequently in D.04-07-022, the CPUC stated that if recorded expenses have been relatively stable for three or more years, the last recorded year is an appropriate base estimate. For this activity the Last Recorded Year method does not account for the variables discussed in testimony to determine the 2025 Test Year forecast. Therefore, the Last Recorded Year method is not appropriate. Linear Trending: In D.89-12-057, and subsequently in D.04-07-022, the CPUC stated that if recorded expenses have been relatively stable for three or more years, the last recorded year is an appropriate base estimate. For this activity the Linear Trending method does not account for the variables discussed in testimony to determine the 2025 Test Year forecast. Therefore, the Linear Trending method is not appropriate.

2025 GRC Year Over Year Variance

(Constant 2022 $000)

Exhibit:	SCE-04 Resiliency
Volume:	5 Pt. 3 - Wildfire Management
Business Planning Element:	Wildfire Management
Activity:	Wildfire Mitigation and Vegetation Management Technology Solutions
Witness:	Jeff Gooding



Cost Type		Recorded/Adj.					Forecast		
		2018	2019	2020	2021	2022	2023	2024	2025
Recorded / Forecast	Labor	0	1	108	168	162	0	0	0
	Non-Labor	0	2,184	2,768	3,743	5,487	8,421	7,733	6,741
	Other	0	0	0	0	0	0	0	0
	Total	**0**	**2,185**	**2,876**	**3,912**	**5,648**	**8,421**	**7,733**	**6,741**

Labor	Prior Year Total	0	1	108	168	162	0	0
	Change	1	107	61	(7)	(162)	0	0
	Total	**1**	**108**	**168**	**162**	**0**	**0**	**0**

Non-Labor	Prior Year Total	0	2,184	2,768	3,743	5,487	8,421	7,733
	Change	2,184	584	975	1,743	2,934	(688)	(992)
	Total	**2,184**	**2,768**	**3,743**	**5,487**	**8,421**	**7,733**	**6,741**

Other	Prior Year Total	0	0	0	0	0	0	0
	Change	0	0	0	0	0	0	0
	Total	**0**	**0**	**0**	**0**	**0**	**0**	**0**

Total Change	Prior Year Total	0	2,185	2,876	3,912	5,648	8,421	7,733
	Change	2,185	691	1,036	1,737	2,772	(688)	(992)
	Total	**2,185**	**2,876**	**3,912**	**5,648**	**8,421**	**7,733**	**6,741**

Due to rounding, totals may not tie to individual items.

2025 GRC Forecast Commentary

(Constant 2022 $000)

Exhibit:	SCE-04 Resiliency
Volume:	5 Pt. 3 - Wildfire Management
Business Planning Element:	Wildfire Management
Activity:	Wildfire Mitigation and Vegetation Management Technology Solutions
Witness:	Jeff Gooding

Summary of Changes: See Testimony

Cost Type		Recorded/Adj.					Forecast		
		2018	2019	2020	2021	2022	2023	2024	2025
Recorded / Forecast	Labor	0	1	108	168	162	0	0	0
	Non-Labor	0	2,184	2,768	3,743	5,487	8,421	7,733	6,741
	Other	0	0	0	0	0	0	0	0
	Total	**0**	**2,185**	**2,876**	**3,912**	**5,648**	**8,421**	**7,733**	**6,741**

Due to rounding, totals may not tie to individual items.

Recorded (2018-2022)

See Testimony

Forecast (2023-2025)

See Testimony

Workpaper Title:

Capital High Fire Risk Inspections and Remediations

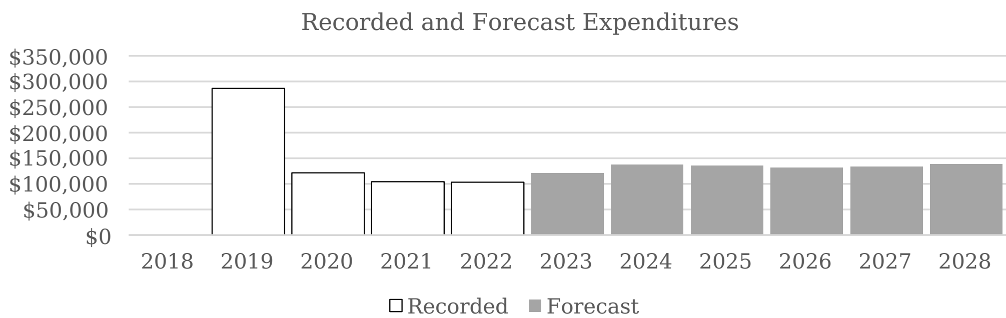
WP SCE-04 Vol. 05 Part 3

Southern California Edison - Capital Workpapers
Capital Workpapers Summary
SUMMARY BY GRC Volume
(Nominal $000)

Exhibit: SCE-04 Resiliency
Volume: 5 Pt. 3 - Wildfire Management

	Recorded Capital Expenditures					Forecast Capital Expenditures					
Description	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Recorded and Forecast Expenditures		286,427	121,552	104,200	103,222	121,076	137,533	135,865	131,726	133,912	138,874
Total Expenditures					615,401						798,985

Due to rounding, totals may not tie to individual items.



	Forecast Capital Expenditures						
GRC Activity	2023	2024	2025	2026	2027	2028	6 yr Total
High Fire Risk Inspections and Remediations	121,076	137,533	135,865	131,726	133,912	138,874	798,985
GRC Total	121,076	137,533	135,865	131,726	133,912	138,874	798,985

Southern California Edison
2025 GRC Capital Workpapers

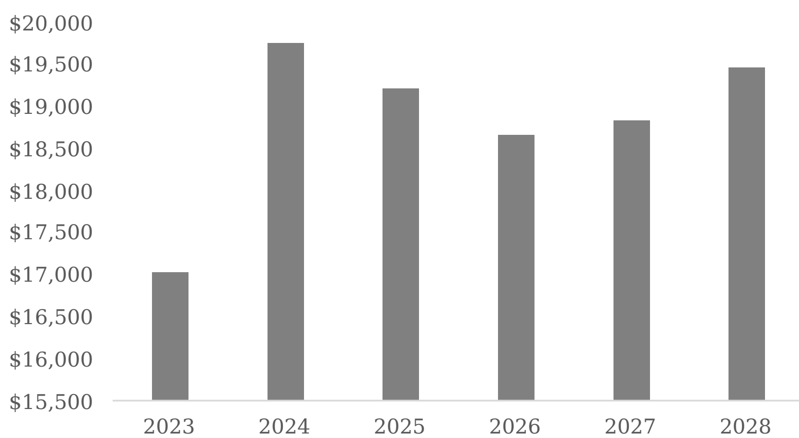
Exhibit:	SCE-04 Resiliency
Volume:	5 Pt. 3 - Wildfire Management
Business Plan Group:	Resiliency
Business Plan Element:	Wildfire Management
GRC Activity:	High Fire Risk Inspections and Remediations
1. Witness:	Ray Fugere
2. Asset type:	DS-LINE
3. In-Service date:	12\1\9999
4. RO Model ID:	1011
5. Pin:	8224
6. CWBS Element:	CETPDWMDB822400
CWBS Description:	Distribution Capital Breakdown Maint
7. SRIIM Eligible:	No

Cost Estimates - Nominal ($000)

2025 GRC - Capital Expenditures Forecast

Year	2023	2024	2025	2026	2027	2028	2023 - 2028 Total
SCE$	17,027	19,747	19,206	18,655	18,830	19,457	112,922

Due to rounding, totals may not tie to individual items.



Southern California Edison
2025 GRC Capital Workpapers

Exhibit:	SCE-04 Resiliency
Volume:	5 Pt. 3 - Wildfire Management
Business Plan Group:	Resiliency
Business Plan Element:	Wildfire Management
GRC Activity:	High Fire Risk Inspections and Remediations

1. Witness:	Ray Fugere
2. Asset type:	DS-LINE
3. In-Service date:	12\1\9999
4. RO Model ID:	1012
5. Pin:	8224
6. CWBS Element:	CETPDWMDP822400
CWBS Description:	Distribution Capital Breakdown Maint
7. SRIIM Eligible:	No

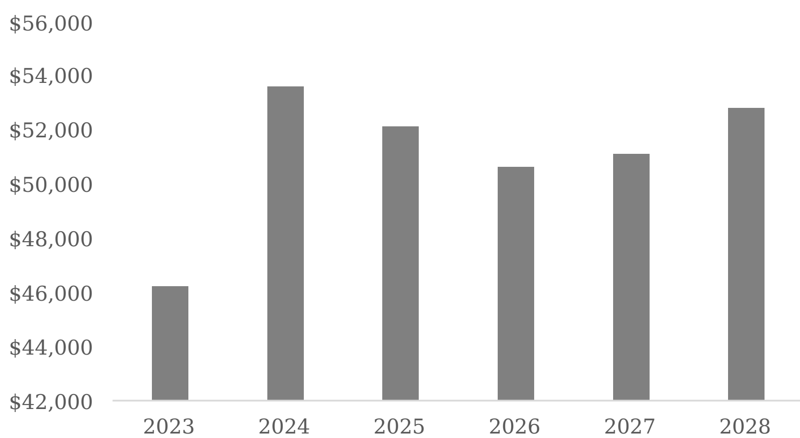
Cost Estimates - Nominal ($000)

2025 GRC - Capital Expenditures Forecast

Year	2023	2024	2025	2026	2027	2028
SCE$	46,219	53,604	52,134	50,640	51,114	52,815

2023 - 2028 Total
306,525

Due to rounding, totals may not tie to individual items.



Southern California Edison
2025 GRC Capital Workpapers

Exhibit:	SCE-04 Resiliency
Volume:	5 Pt. 3 - Wildfire Management
Business Plan Group:	Resiliency
Business Plan Element:	Wildfire Management
GRC Activity:	High Fire Risk Inspections and Remediations

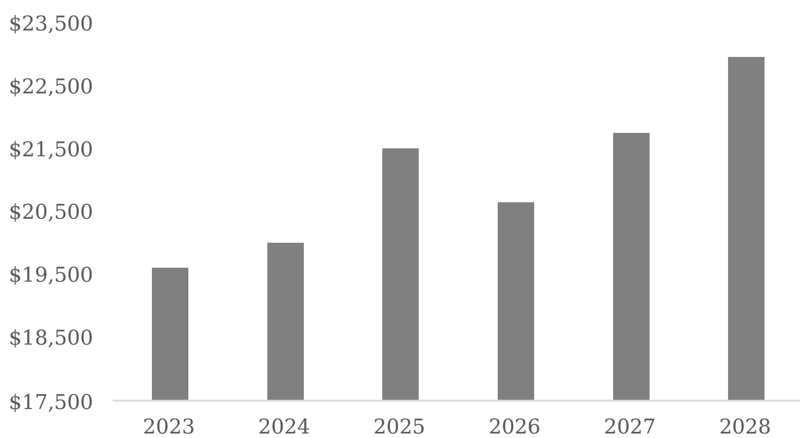
1. Witness:	Ray Fugere
2. Asset type:	TR-LINE
3. In-Service date:	12\1\9999
4. RO Model ID:	986
5. Pin:	8224
6. CWBS Element:	CETPDWMTP822400
CWBS Description:	EOI Replacements - T (CPUC)
7. SRIIM Eligible:	Yes

Cost Estimates - Nominal ($000)

2025 GRC - Capital Expenditures Forecast

Year	2023	2024	2025	2026	2027	2028	2023 - 2028 Total
SCE$	19,603	20,003	21,492	20,641	21,739	22,945	126,422

Due to rounding, totals may not tie to individual items.



Southern California Edison
2025 GRC Capital Workpapers

Exhibit:	SCE-04 Resiliency
Volume:	5 Pt. 3 - Wildfire Management
Business Plan Group:	Resiliency
Business Plan Element:	Wildfire Management
GRC Activity:	High Fire Risk Inspections and Remediations

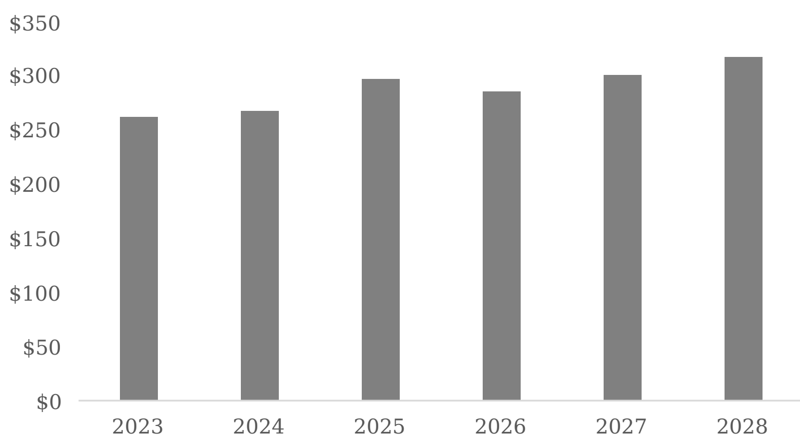
1. Witness:	Ray Fugere
2. Asset type:	TR-LINE
3. In-Service date:	12\1\9999
4. RO Model ID:	987
5. Pin:	8224
6. CWBS Element:	CETPDWMTP822401
CWBS Description:	EOI Replacements - T (FERC)
7. SRIIM Eligible:	Yes

Cost Estimates - Nominal ($000)

2025 GRC - Capital Expenditures Forecast

Year	2023	2024	2025	2026	2027	2028	2023 - 2028 Total
SCE$	262	268	297	286	301	317	1,731

Due to rounding, totals may not tie to individual items.



Southern California Edison
2025 GRC Capital Workpapers

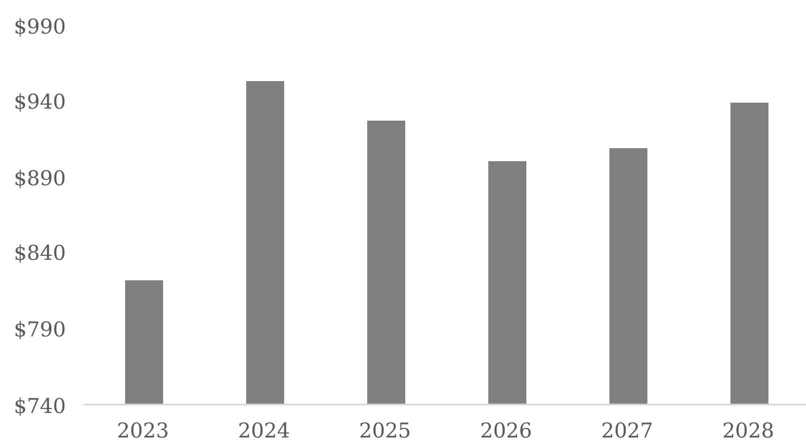
Exhibit:	SCE-04 Resiliency
Volume:	5 Pt. 3 - Wildfire Management
Business Plan Group:	Resiliency
Business Plan Element:	Wildfire Management
GRC Activity:	High Fire Risk Inspections and Remediations
1. Witness:	Ray Fugere
2. Asset type:	DS-LINE
3. In-Service date:	12\1\9999
4. RO Model ID:	621
5. Pin:	8224
6. CWBS Element:	CETPDFRDF826600
CWBS Description:	Emergent Dry Fuels Remediation
7. SRIIM Eligible:	No

Cost Estimates - Nominal ($000)

2025 GRC - Capital Expenditures Forecast

Year	2023	2024	2025	2026	2027	2028	2023 - 2028 Total
SCE$	822	953	927	900	909	939	5,449

Due to rounding, totals may not tie to individual items.



Southern California Edison
2025 GRC Capital Workpapers

Exhibit:	SCE-04 Resiliency
Volume:	5 Pt. 3 - Wildfire Management
Business Plan Group:	Resiliency
Business Plan Element:	Wildfire Management
GRC Activity:	High Fire Risk Inspections and Remediations

1. Witness:	Ray Fugere
2. Asset type:	DS-LINE
3. In-Service date:	12\1\9999
4. RO Model ID:	82
5. Pin:	8224
6. CWBS Element:	CETPDWMOCMTW
CWBS Description:	Metro West
7. SRIIM Eligible:	Yes

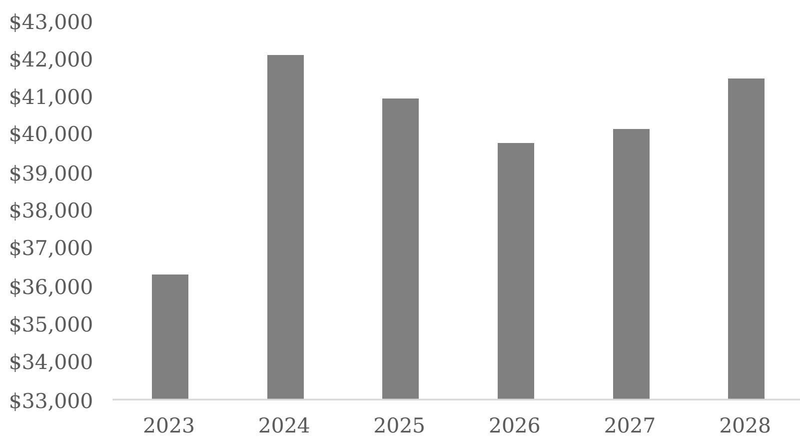
Cost Estimates - Nominal ($000)

2025 GRC - Capital Expenditures Forecast

Year	2023	2024	2025	2026	2027	2028
SCE$	36,290	42,089	40,935	39,762	40,134	41,469

2023 - 2028 Total
240,679

Due to rounding, totals may not tie to individual items.



Southern California Edison
2025 GRC Capital Workpapers

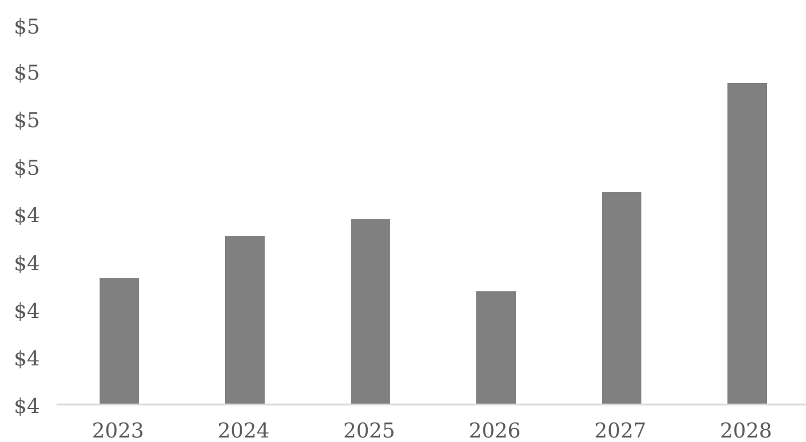
Exhibit:	SCE-04 Resiliency
Volume:	5 Pt. 3 - Wildfire Management
Business Plan Group:	Resiliency
Business Plan Element:	Wildfire Management
GRC Activity:	High Fire Risk Inspections and Remediations
1. Witness:	Ray Fugere
2. Asset type:	TR-LINE
3. In-Service date:	12\1\9999
4. RO Model ID:	622
5. Pin:	8224
6. CWBS Element:	CETPDFRTF822601
CWBS Description:	Trans Emerg Dry Fuels Remediation FERC
7. SRIIM Eligible:	No

Cost Estimates - Nominal ($000)

2025 GRC - Capital Expenditures Forecast

Year	2023	2024	2025	2026	2027	2028	2023 - 2028 Total
SCE$	4	4	4	4	4	5	26

Due to rounding, totals may not tie to individual items.



Southern California Edison
2025 GRC Capital Workpapers

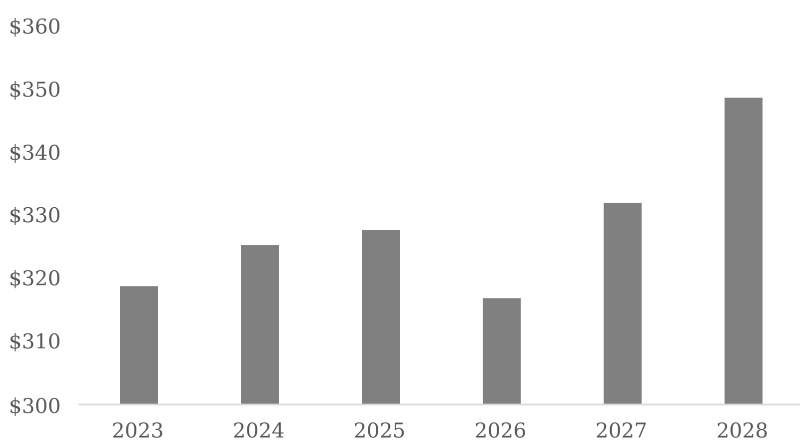
Exhibit:	SCE-04 Resiliency
Volume:	5 Pt. 3 - Wildfire Management
Business Plan Group:	Resiliency
Business Plan Element:	Wildfire Management
GRC Activity:	High Fire Risk Inspections and Remediations
1. Witness:	Ray Fugere
2. Asset type:	TR-LINE
3. In-Service date:	12\1\9999
4. RO Model ID:	623
5. Pin:	8224
6. CWBS Element:	CETPDFRTF826600
CWBS Description:	Trans Emergent Dry Fuels Remediation
7. SRIIM Eligible:	No

Cost Estimates - Nominal ($000)

2025 GRC - Capital Expenditures Forecast

Year	2023	2024	2025	2026	2027	2028	2023 - 2028 Total
SCE$	319	325	328	317	332	349	1,969

Due to rounding, totals may not tie to individual items.



Southern California Edison
2025 GRC Capital Workpapers

Exhibit:	SCE-04 Resiliency
Volume:	5 Pt. 3 - Wildfire Management
Business Plan Group:	Resiliency
Business Plan Element:	Wildfire Management
GRC Activity:	High Fire Risk Inspections and Remediations

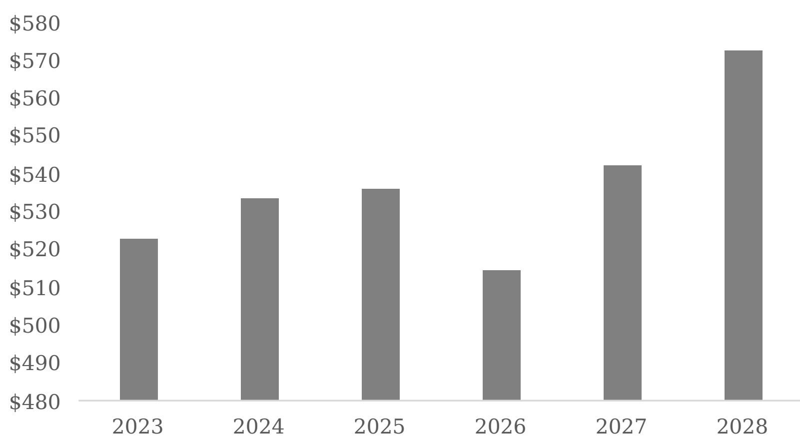
1. Witness:	Ray Fugere
2. Asset type:	TR-LINE
3. In-Service date:	12\1\9999
4. RO Model ID:	1015
5. Pin:	8224
6. CWBS Element:	CETPDWMTS822400
CWBS Description:	Transmission Splice CPUC
7. SRIIM Eligible:	No

Cost Estimates - Nominal ($000)

2025 GRC - Capital Expenditures Forecast

Year	2023	2024	2025	2026	2027	2028	2023 - 2028 Total
SCE$	523	533	536	514	542	572	3,221

Due to rounding, totals may not tie to individual items.



Southern California Edison
2025 GRC Capital Workpapers

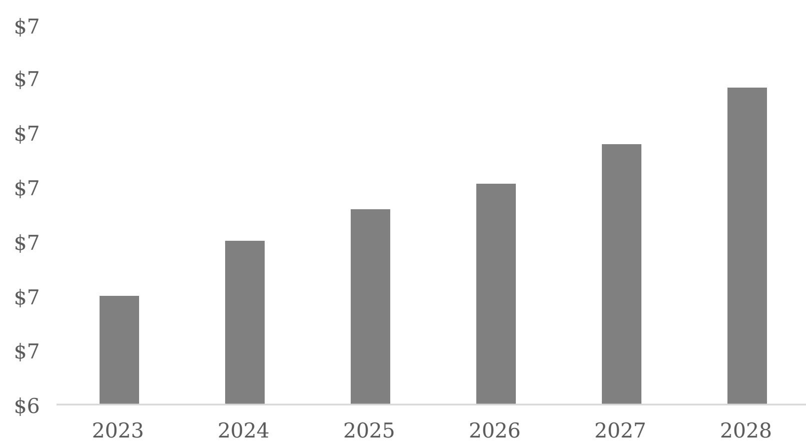
Exhibit:	SCE-04 Resiliency
Volume:	5 Pt. 3 - Wildfire Management
Business Plan Group:	Resiliency
Business Plan Element:	Wildfire Management
GRC Activity:	High Fire Risk Inspections and Remediations
1. Witness:	Ray Fugere
2. Asset type:	TR-LINE
3. In-Service date:	12\1\9999
4. RO Model ID:	150
5. Pin:	8224
6. CWBS Element:	CETPDWMTS822401
CWBS Description:	Transmission Splice FERC
7. SRIIM Eligible:	No

Cost Estimates - Nominal ($000)

2025 GRC - Capital Expenditures Forecast

Year	2023	2024	2025	2026	2027	2028	2023 - 2028 Total
SCE$	7	7	7	7	7	7	41

Due to rounding, totals may not tie to individual items.



Workpaper Title:

Capital Wildfire Mitigation and Vegetation Management Technology Solutions

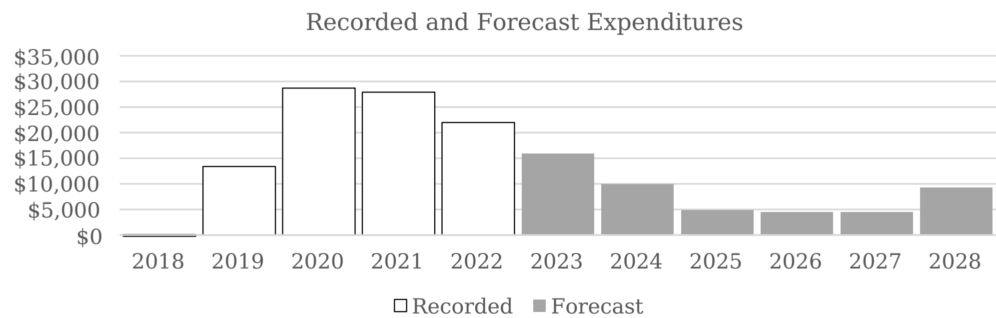
WP SCE-04 Vol. 05 Part 3

Southern California Edison - Capital Workpapers
Capital Workpapers Summary
SUMMARY BY GRC Volume
(Nominal $000)

Exhibit: SCE-04 Resiliency
Volume: 5 Pt. 3 - Wildfire Management

	Recorded Capital Expenditures					Forecast Capital Expenditures					
Description	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Recorded and Forecast Expenditures	100	13,391	28,700	27,903	21,981	15,846	9,910	4,825	4,492	4,480	9,219
Total Expenditures					92,075						48,771

Due to rounding, totals may not tie to individual items.



	Forecast Capital Expenditures						
GRC Activity	2023	2024	2025	2026	2027	2028	6 yr Total
Wildfire Mitigation and Vegetation Management Technology Solutions	15,846	9,910	4,825	4,492	4,480	9,219	48,771
GRC Total	15,846	9,910	4,825	4,492	4,480	9,219	48,771

Southern California Edison
2025 GRC Capital Workpapers

Exhibit:	SCE-04 Resiliency
Volume:	5 Pt. 3 - Wildfire Management
Business Plan Group:	Resiliency
Business Plan Element:	Wildfire Management
GRC Activity:	Wildfire Mitigation and Vegetation Management Technology Solutions

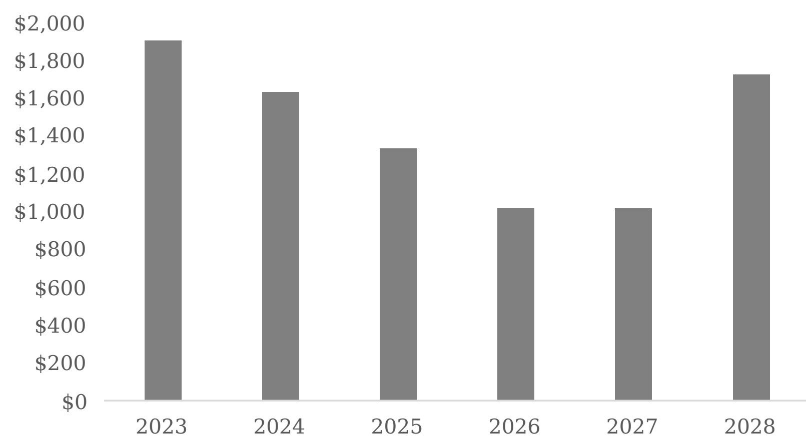
1. Witness:	Jeff Gooding
2. Asset type:	5YR SWA
3. In-Service date:	12\1\9999
4. RO Model ID:	478
5. Pin:	8224
6. CWBS Element:	CIT00WMCS822405
CWBS Description:	Aerial & Transmission Ground Work
7. SRIIM Eligible:	No

Cost Estimates - Nominal ($000)

2025 GRC - Capital Expenditures Forecast

Year	2023	2024	2025	2026	2027	2028	2023 - 2028 Total
SCE$	1,902	1,628	1,331	1,019	1,016	1,723	8,620

Due to rounding, totals may not tie to individual items.



Southern California Edison
2025 GRC Capital Workpapers

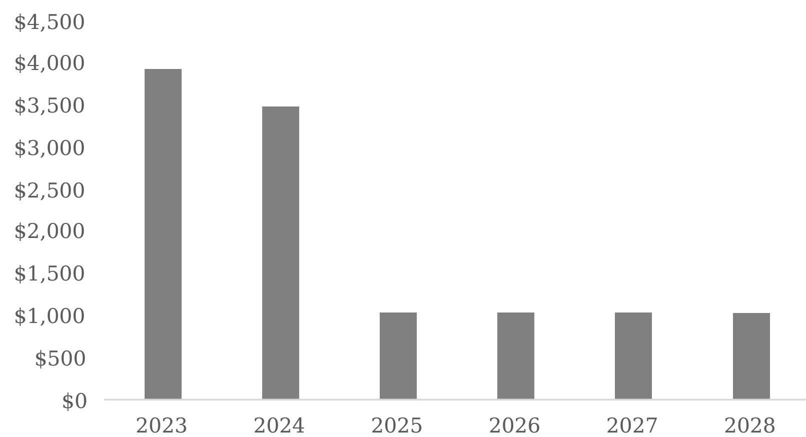
Exhibit:	SCE-04 Resiliency
Volume:	5 Pt. 3 - Wildfire Management
Business Plan Group:	Resiliency
Business Plan Element:	Wildfire Management
GRC Activity:	Wildfire Mitigation and Vegetation Management Technology Solutions
1. Witness:	Jeff Gooding
2. Asset type:	5YR SWA
3. In-Service date:	12\1\9999
4. RO Model ID:	1052
5. Pin:	8224
6. CWBS Element:	CIT00WMCS822434
CWBS Description:	Aerial LiDAR - Data Integration
7. SRIIM Eligible:	No

Cost Estimates - Nominal ($000)

2025 GRC - Capital Expenditures Forecast

Year	2023	2024	2025	2026	2027	2028	2023 - 2028 Total
SCE$	3,923	3,480	1,033	1,035	1,032	1,029	11,531

Due to rounding, totals may not tie to individual items.



Southern California Edison
2025 GRC Capital Workpapers

Exhibit:	SCE-04 Resiliency
Volume:	5 Pt. 3 - Wildfire Management
Business Plan Group:	Resiliency
Business Plan Element:	Wildfire Management
GRC Activity:	Wildfire Mitigation and Vegetation Management Technology Solutions
1. Witness:	Jeff Gooding
2. Asset type:	5YR SWA
3. In-Service date:	12\1\9999
4. RO Model ID:	480
5. Pin:	8224
6. CWBS Element:	CIT00WMCS822409
CWBS Description:	Assisted Reality Capture Device
7. SRIIM Eligible:	No

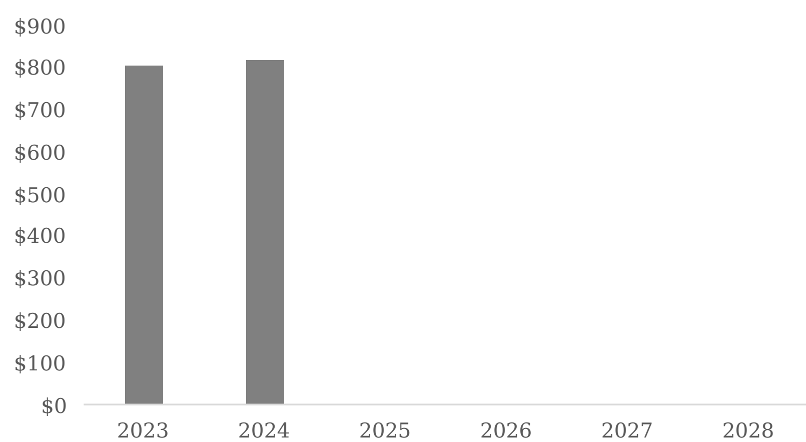
Cost Estimates - Nominal ($000)

2025 GRC - Capital Expenditures Forecast

Year	2023	2024	2025	2026	2027	2028
SCE$	803	817	0	0	0	0

2023 - 2028 Total
1,620

Due to rounding, totals may not tie to individual items.



Southern California Edison
2025 GRC Capital Workpapers

Exhibit:	SCE-04 Resiliency
Volume:	5 Pt. 3 - Wildfire Management
Business Plan Group:	Resiliency
Business Plan Element:	Wildfire Management
GRC Activity:	Wildfire Mitigation and Vegetation Management Technology Solutions

1. Witness:	Jeff Gooding
2. Asset type:	5YR SWA
3. In-Service date:	12\1\9999
4. RO Model ID:	482
5. Pin:	8224
6. CWBS Element:	CIT00WMCS822411
CWBS Description:	Distribution Ground Inspect App
7. SRIIM Eligible:	No

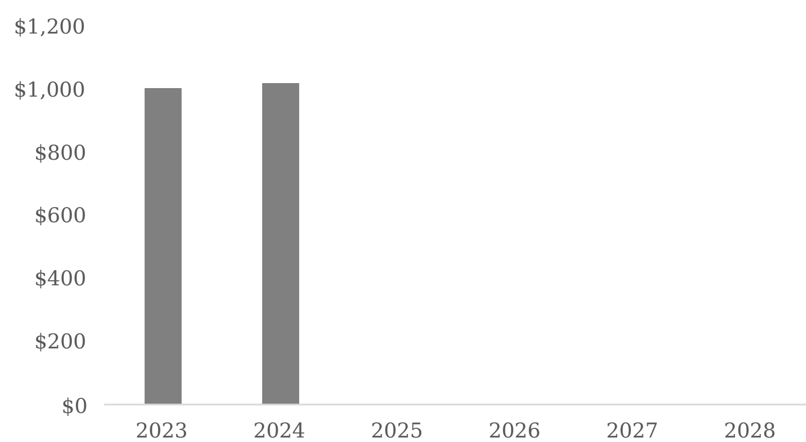
Cost Estimates - Nominal ($000)

2025 GRC - Capital Expenditures Forecast

Year	2023	2024	2025	2026	2027	2028
SCE$	1,000	1,016	0	0	0	0

2023 - 2028 Total
2,016

Due to rounding, totals may not tie to individual items.



Southern California Edison
2025 GRC Capital Workpapers

Exhibit:	SCE-04 Resiliency
Volume:	5 Pt. 3 - Wildfire Management
Business Plan Group:	Resiliency
Business Plan Element:	Wildfire Management
GRC Activity:	Wildfire Mitigation and Vegetation Management Technology Solutions

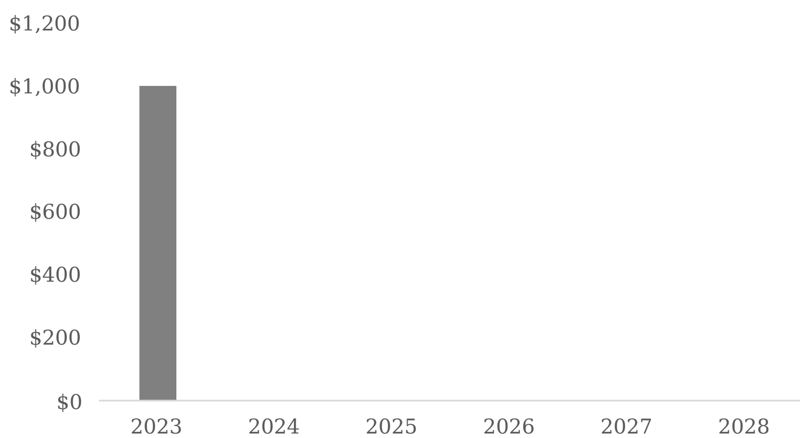
1. Witness:	Jeff Gooding
2. Asset type:	5YR SWA
3. In-Service date:	12\1\9999
4. RO Model ID:	483
5. Pin:	8224
6. CWBS Element:	CIT00WMCS822413
CWBS Description:	EOI (Enhanced Overhead Inspection)
7. SRIIM Eligible:	No

Cost Estimates - Nominal ($000)

2025 GRC - Capital Expenditures Forecast

Year	2023	2024	2025	2026	2027	2028	2023 - 2028 Total
SCE$	996	0	0	0	0	0	996

Due to rounding, totals may not tie to individual items.



Southern California Edison
2025 GRC Capital Workpapers

Exhibit:	SCE-04 Resiliency
Volume:	5 Pt. 3 - Wildfire Management
Business Plan Group:	Resiliency
Business Plan Element:	Wildfire Management
GRC Activity:	Wildfire Mitigation and Vegetation Management Technology Solutions

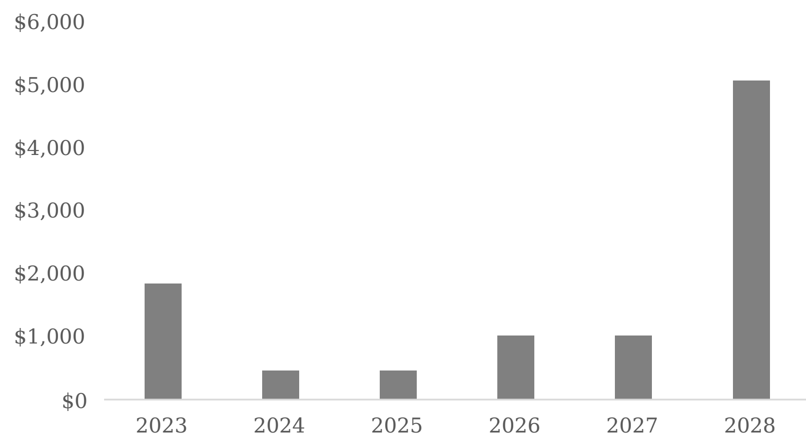
1. Witness:	Jeff Gooding
2. Asset type:	5YR SWA
3. In-Service date:	12\1\9999
4. RO Model ID:	484
5. Pin:	8224
6. CWBS Element:	CIT00WMCS822415
CWBS Description:	Ezy Data
7. SRIIM Eligible:	No

Cost Estimates - Nominal ($000)

2025 GRC - Capital Expenditures Forecast

Year	2023	2024	2025	2026	2027	2028	2023 - 2028 Total
SCE$	1,835	458	458	1,015	1,012	5,050	9,829

Due to rounding, totals may not tie to individual items.



Southern California Edison
2025 GRC Capital Workpapers

Exhibit:	SCE-04 Resiliency
Volume:	5 Pt. 3 - Wildfire Management
Business Plan Group:	Resiliency
Business Plan Element:	Wildfire Management
GRC Activity:	Wildfire Mitigation and Vegetation Management Technology Solutions

1. Witness:	Jeff Gooding
2. Asset type:	5YR SWA
3. In-Service date:	12\1\2023
4. RO Model ID:	486
5. Pin:	8224
6. CWBS Element:	CIT00WMCS822420
CWBS Description:	FMEA Failure Interaction Tool
7. SRIIM Eligible:	No

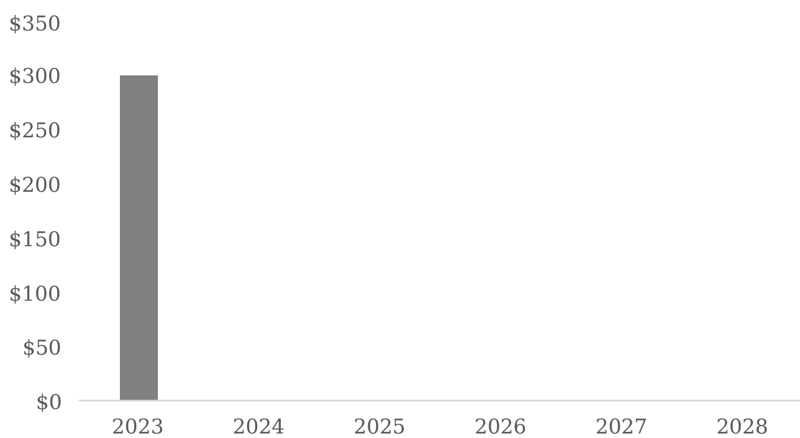
Cost Estimates - Nominal ($000)

2025 GRC - Capital Expenditures Forecast

Year	2023	2024	2025	2026	2027	2028
SCE$	300	0	0	0	0	0

2023 - 2028 Total
300

Due to rounding, totals may not tie to individual items.



Southern California Edison
2025 GRC Capital Workpapers

Exhibit:	SCE-04 Resiliency
Volume:	5 Pt. 3 - Wildfire Management
Business Plan Group:	Resiliency
Business Plan Element:	Wildfire Management
GRC Activity:	Wildfire Mitigation and Vegetation Management Technology Solutions

1. Witness:	Jeff Gooding
2. Asset type:	5YR SWA
3. In-Service date:	12\1\9999
4. RO Model ID:	481
5. Pin:	8224
6. CWBS Element:	CIT00WMCS822410
CWBS Description:	Insp w Artificial Intel/Machine Learning
7. SRIIM Eligible:	No

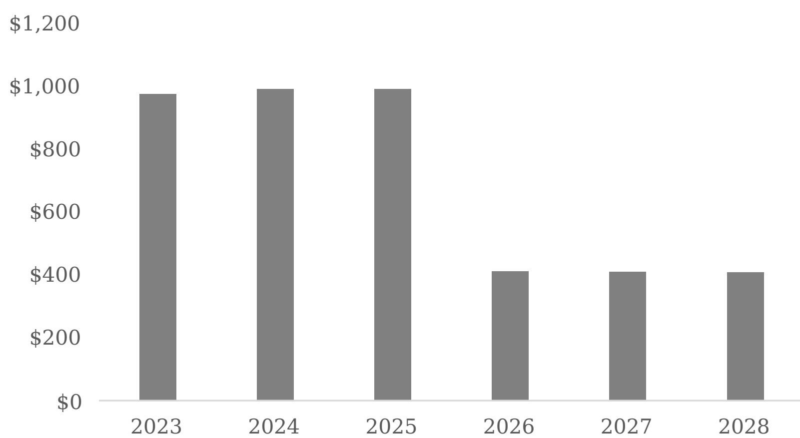
Cost Estimates - Nominal ($000)

2025 GRC - Capital Expenditures Forecast

Year	2023	2024	2025	2026	2027	2028
SCE$	971	987	987	409	408	407

2023 - 2028 Total
4,168

Due to rounding, totals may not tie to individual items.



Southern California Edison
2025 GRC Capital Workpapers

Exhibit:	SCE-04 Resiliency
Volume:	5 Pt. 3 - Wildfire Management
Business Plan Group:	Resiliency
Business Plan Element:	Wildfire Management
GRC Activity:	Wildfire Mitigation and Vegetation Management Technology Solutions

1. Witness:	Jeff Gooding
2. Asset type:	5YR SWA
3. In-Service date:	1\1\2024
4. RO Model ID:	1093
5. Pin:	8224
6. CWBS Element:	CIT00WMCS822435
CWBS Description:	LiDAR Salesforce Digital Workflow
7. SRIIM Eligible:	No

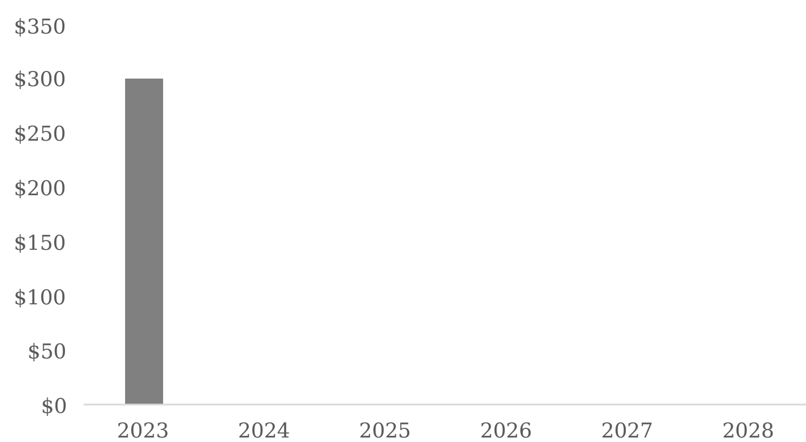
Cost Estimates - Nominal ($000)

2025 GRC - Capital Expenditures Forecast

Year	2023	2024	2025	2026	2027	2028
SCE$	300	0	0	0	0	0

2023 - 2028 Total
300

Due to rounding, totals may not tie to individual items.



Southern California Edison
2025 GRC Capital Workpapers

Exhibit:	SCE-04 Resiliency
Volume:	5 Pt. 3 - Wildfire Management
Business Plan Group:	Resiliency
Business Plan Element:	Wildfire Management
GRC Activity:	Wildfire Mitigation and Vegetation Management Technology Solutions

1. Witness:	Jeff Gooding
2. Asset type:	5YR SWA
3. In-Service date:	12\1\9999
4. RO Model ID:	485
5. Pin:	8224
6. CWBS Element:	CIT00WMCS822419
CWBS Description:	Wildfire Safety Data Mgmt (WiSDM)
7. SRIIM Eligible:	No

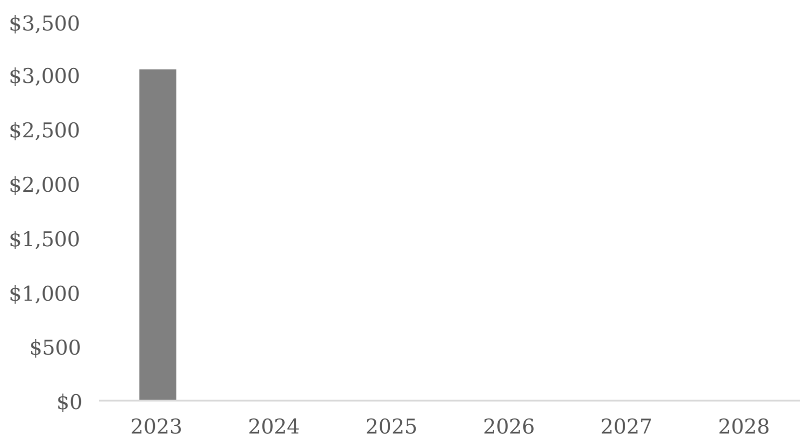
Cost Estimates - Nominal ($000)

2025 GRC - Capital Expenditures Forecast

Year	2023	2024	2025	2026	2027	2028
SCE$	3,058	0	0	0	0	0

2023 - 2028 Total
3,058

Due to rounding, totals may not tie to individual items.



Southern California Edison
2025 GRC Capital Workpapers

Exhibit:	SCE-04 Resiliency
Volume:	5 Pt. 3 - Wildfire Management
Business Plan Group:	Resiliency
Business Plan Element:	Wildfire Management
GRC Activity:	Wildfire Mitigation and Vegetation Management Technology Solutions
1. Witness:	Jeff Gooding
2. Asset type:	5YR SWA
3. In-Service date:	12\1\9999
4. RO Model ID:	1091
5. Pin:	8224
6. CWBS Element:	CIT00WMCS822440
CWBS Description:	Wildfire Safety Data Mgmt (WiSDM)Phase 2
7. SRIIM Eligible:	No

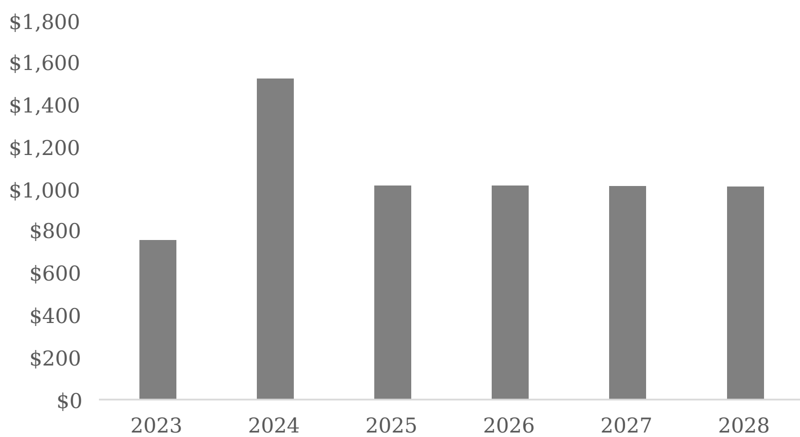
Cost Estimates - Nominal ($000)

2025 GRC - Capital Expenditures Forecast

Year	2023	2024	2025	2026	2027	2028
SCE$	756	1,524	1,015	1,015	1,012	1,010

2023 - 2028 Total
6,332

Due to rounding, totals may not tie to individual items.



Workpaper Title:

Distribution O&M

WP SCE-04 Vol. 05 Part 3

O&M Forecast - Aerial Transmission T + AOC, 360 D + AOC, Distribution IR Scan

Programs (2023)	**Total Inspections (A) (1)**		**Cost Per (B) (2)**		**Total O&M Cost (A x B)**
Aerial Inspections - T	25,500	$	425	$	10,837,500
AOC Aerial Inspections - T	1,000	$	286	$	286,000
HFRA 360 Program - D	186,000	$	162	$	30,132,000
HFRA 360 Program - D AOC	30,000	$	125	$	3,750,000
Infrared Inspection Program - Distribution IR	5,158	$	92	$	474,536

Escalation	**2023**	**2024**	**2025**
Transmission (Index)	1.036	1.052	1.059
Transmission (Year Over Year)	3.64%	1.54%	0.59%

		2023		**2024**		**2025**
Aerial Inspections - T (Nominal)	$	10,837,500	$	10,837,500	$	11,003,946
Escalation			$	166,446	$	65,077
Nominal to Constant Adjusment	$	1,567,500	$	166,054	$	148,978
Total Aerial Inspections - T (Constant)	**$**	**12,405,000**	**$**	**11,170,000**	**$**	**11,218,000**
AOC Aerial Inspections - T (Nominal)	$	286,000	$	286,000	$	290,392
Escalation			$	4,392	$	1,717
Nominal to Constant Adjusment	$	(5,448)	$	8,608	$	13,890
Total AOC Aerial Inspections -T (Constant)	**$**	**280,552**	**$**	**299,000**	**$**	**306,000**
HFRA 360 Program - D (Nominal)	$	30,132,000	$	30,132,000	$	30,594,777
Escalation			$	462,777	$	180,936
Nominal to Constant Adjusment	$	106,000	$	(268,777)	$	(250,712)
HFRA 360 Program - D (Constant)	**$**	**30,238,000**	**$**	**30,326,000**	**$**	**30,525,000**
HFRA 360 Program - D AOC (Nominal)	$	3,750,000	$	3,750,000	$	3,807,594
Escalation			$	57,594	$	22,518
Nominal to Constant Adjusment	$	(9,000)	$	(64,594)	$	(80,112)
HFRA 360 Program - D AOC (Constant)	**$**	**3,741,000**	**$**	**3,743,000**	**$**	**3,750,000**
Infrared Inspection Program - Distribution IR (Nominal)	$	474,536	$	474,536	$	481,824
Escalation			$	7,288	$	2,849
Nominal to Constant Adjusment	$	102,464	$	(824)	$	(674)
Infrared Inspection Program - Distribution IR (Constant $)	**$**	**577,000**	**$**	**481,000**	**$**	**484,000**

Assumptions:

Inspections:

(1) 2023 Inspection numbers from Vegetation & Inspection Strategy as of 10.06.22.

Cost Pers:

(2) For Aerial Inspection - T programs, cost-per was developed using a 1-year historical average due to a significant pricing change between 2021 to 2022 for the data collection. For the HFRA 360 Program - D and HFRA 360 Program - D AOC, being a new program in 2023, a bottom up forecast was developed inclusive of 3rd party vendor costs, internal electric utility staff, and other overhead costs. The Infrared Inspection Program - Distribution IR forecast was developed using a 3-year historical average.

Workpaper Title:

Transmission O&M

WP SCE-04 Vol. 05 Part 3

O&M Forecast - HFRI & AOC Repairs/ Replacements - Transmission

Transmission Inspection Notification Info

Previous Year Notification Roll Over (2023)	Total Notifications (A) [3]	Rollover Rate (B)	Adjusted Notifications (A x B)	Avg Cost/Notification [6]	Total O&M Cost
Ground Risk-Informed notifications due after 2022	258	85.0%	219	$ 2,112	$ 463,162
Ground GO95 Risk-Informed notifications due 2022/prior	761	60.0%	457	$ 2,112	$ 964,339
Ground Non-GO95 Risk-Informed notifications due 2022/prior	111	30.0%	33	$ 2,112	$ 70,330
Aerial Risk-Informed notifications due after 2022	129	85.0%	110	$ 2,112	$ 231,581
Aerial GO95 Risk-Informed notifications due 2022/prior	23	60.0%	14	$ 2,112	$ 29,146
Aerial Non-GO95 Risk-Informed notifications due 2022/prior	112	30.0%	34	$ 2,112	$ 70,963
				Total	**$ 1,829,520**

Inspections & Found Notifications (2023 - 2024)	Total Inspections (C) [1]	Find Rate (D) [4]	Execution Rate (E) [5]	Adjusted Notifications (C x D x E)	Avg Cost/Notification [6]	Total O&M Cost
HFRI - Ground	23,501	2.52%	79.0%	468	$ 2,112	$ 988,116
HFRI - Aerial	29,401	1.95%	79.0%	453	$ 2,112	$ 956,572
AOC - Ground	1,000	2.52%	79.0%	20	$ 2,112	$ 42,046
AOC - Aerial	1,000	1.95%	79.0%	15	$ 2,112	$ 32,535
					Total	**$ 2,019,269**

Inspections & Found Notifications (2023 - 2024) [7]	Total X-Ray Inspections (F)	Find Rate (G)	Adjusted Notifications (F x G)	Avg Cost/Notification	Total O&M Cost
Transmission Splice	75	34.43%	26	$ 4,000	$ 103,279
				Total HFRI (2023 - 2024)	**$ 3,877,487**
				Total AOC (2023 - 2024)	**$ 74,581**

Escalation	2023	2024	2025
Transmission (Index)	1.036	1.052	1.059
Transmission (Year Over Year)	3.64%	1.54%	0.59%

	2023	2024	2025
HFRI Repairs/ Replacements - T (Nominal)	$ 3,877,487	$ 3,877,487	$ 3,937,038
2025 Increase (all HFRI) [2]			$ 238,000
Escalation		$ 59,552	$ 23,283
Nominal to Constant Adjustment	$ 31,839	$ 5,825	$ 10,411
Total HFRI Repairs/ Replacements - T (Constant $)	**$ 3,909,326**	**$ 3,942,863**	**$ 4,208,733**
AOC Repairs/ Replacements - T (Nominal)	$ 74,581	$ 74,581	$ 75,726
Escalation		$ 1,145	$ 448
Nominal to Constant Adjustment	$ (557)	$ (1,216)	$ (1,430)
Total AOC Repairs/ Replacements - T (Constant $)	**$ 74,024**	**$ 74,510**	**$ 74,744**

Assumptions:

Inspections:

[1] *2023 Inspection numbers from Vegetation & Inspection Strategy as of 10.06.22. 5,900 "Risk 3" structures carved out of scope as compliance. Number of HFRI Inspection scope (2024 - 2032) assumed to stay the same as 2023.*

[2] *2025 Additional amount in O&M Remediations - estimated $238k. The increase in 2025 accounts for the increase in scope to forecast all High Fire Inspections and subsequent remediations, including repairs or replacements on structures that were only previously counted as part of routine, compliance-based inspection work in HFRA*

Roll Over:

[3] *Rollover scope as of 8/29/22 from Notif_Pri Report*

Find Rates:

[4] *Ground O&M Find Rate calculated based on 2022 HFRA inspection P2 blended find rate (YTD - July), removing half of the ROW notifications (Starting in 2023 brushing (ROW O&M) notifications will no longer be assigned as part of Ground Transmission HFRI Inspections). Aerial Find Rates for O&M from Inspections Data Intelligence team - 8/30/22*

Execution Rate:

[5] *O&M execution find rates based on aging data from Notif_Pri Report. Total Field Complete Notifications (2022 & Prior) & Time to Complete*

Cost Pers:

[6] *O&M Remediation cost per calculated using 2022 completed notifications & cost. 2023 will assume a 50/50 split of ROW & TCM work*

Transmission Splice:

[7] *O&M remediations (shunts) based on 2022 YTD findings for X-Ray inspections and estimated cost per. Forecast included in HFRI Repairs / Replacements*

O&M Forecast - HFRI & AOC Inspections - Transmission

Transmission Inspections	**Total Inspections (A) (1)**	**Cost Per (B) (3)**	**Total O&M Cost (A x B)**
HRFI Inspections - Ground (2023)	23,501	$ 152	$ 3,564,863
AOC Inspections - Ground (2023)	1,000	$ 152	$ 151,690
Transmission Splice Inspections (2023) (4)			$ 1,700,000

Escalation	**2023**	**2024**	**2025**
Transmission (Index)	1.036	1.052	1.059
Transmission (Year Over Year)	3.64%	1.54%	0.59%

	2023	**2024**	**2025**
HFRI Inspections - T (Nominal)	$ 3,564,863	$ 3,564,863	$ 3,619,613
2025 Increase (all HFRI) (2)			$ 788,177
Escalation		$ 54,750	$ 21,406
Nominal to Constant Adjusment	$ (1,556)	$ (58,163)	$ (87,762)
Total HFRI Inspections - T (Constant $)	**$ 3,563,306**	**$ 3,561,450**	**$ 4,341,434**
AOC Inspections - T (Nominal)	$ 151,690	$ 151,690	$ 154,020
Escalation		$ 2,330	$ 911
Nominal to Constant Adjusment	$ (1,046)	$ (2,428)	$ (3,009)
Total AOC Inspections - T (Constant $)	**$ 150,644**	**$ 151,592**	**$ 151,921**
Transmission Splice Inspections (Nominal)	$ 1,700,000	$ 1,700,000	$ 1,726,109
Escalation		$ 26,109	$ 10,208
Nominal to Constant Adjusment	$ (11,943)	$ (26,091)	$ (30,617)
Total Transmission Splice Inspections - T (Constant $)	**$ 1,688,057**	**$ 1,700,018**	**$ 1,705,700**

Assumptions:

Inspections:

(1) 2023 Inspection numbers from Vegetation & Inspection Strategy as of 10.06.22. 5,900 "Risk 3" structures carved out of scope as compliance. Number of HFRI Inspection scope (2024 - 2032) assumed to stay the same as 2023

(2) 2025 Additional amount to O&M Inspections- estimated $788k. The increase in 2025 accounts for the increase in scope to forecast all High Fire Inspections on structures that were only previously counted as part of routine, compliance-based inspection work in HFRA

Cost Pers:

(3) Inspections cost per calculated using 2021 realized cost for HFRI inspections ($2,181,148 total spend / 14,379 total HFRI inspections)

Transmission Splice:

(4) Because this is a new program (started in 2022), there is not enough data for cost pers

Workpaper Title:

Distribution Remediations

WP SCE-04 Vol. 05 Part 3

Capital Forecast: EOI/HFRI Remediations - Distribution

	Forecasted					
Distribution Capital Breakdown Maintenance	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**
Number of Priority 1 Notifications[1]	975	1,087	1,048	1,021	1,021	1,021
Priority 1 Notification Cost per Unit[2]	$17	$18	$18	$18	$18	$19
Priority 1 Subtotal	$ 16,407	$ 19,183	$ 18,945	$ 18,616	$ 18,752	$ 19,015
Adjustment	$ 620	$ 564	$ 260	$ 39	$ 78	$ 442
Subtotal	$ 17,027	$ 19,747	$ 19,206	$ 18,655	$ 18,830	$ 19,457
AOC Repairs / Replacements						
Number of Priority 2 Notifications[1]	47	52	51	49	49	49
Priority 2 Notification Cost per Unit[2]	$17	$18	$18	$18	$18	$19
Priority 2 Subtotal	$ 792	$ 926	$ 914	$ 898	$ 905	$ 918
Adjustment	$ 30	$ 27	$ 13	$ 2	$ 4	$ 21
Subtotal	$ 822	$ 953	$ 927	$ 900	$ 909	$ 939
Distribution Capital Preventative Maintenance						
Number of Priority 2 Notifications[1]	2,648	2,950	2,844	2,771	2,772	2,771
Priority 2 Notification Cost per Unit[2]	$17	$18	$18	$18	$18	$19
Priority 2 Subtotal	$ 44,536	$ 52,073	$ 51,427	$ 50,533	$ 50,902	$ 51,616
Adjustment	$ 1,682	$ 1,531	$ 707	$ 107	$ 212	$ 1,199
Subtotal	$ 46,219	$ 53,604	$ 52,134	$ 50,640	$ 51,114	$ 52,815
Risk Informed Inspections						
Number of Priority 2 Notifications[1]	2,079	2,316	2,233	2,176	2,177	2,175
Priority 2 Notification Cost per Unit[2]	$17	$18	$18	$18	$18	$19
Priority 2 Subtotal	$ 34,969	$ 40,887	$ 40,379	$ 39,678	$ 39,968	$ 40,528
Adjustment	$ 1,321	$ 1,202	$ 555	$ 84	$ 167	$ 941
Subtotal	$ 36,290	$ 42,089	$ 40,935	$ 39,762	$ 40,134	$ 41,469
Total HFRA Replacements	$ 100,358	$ 116,393	$ 113,201	$ 109,957	$ 110,988	$ 114,679
Escalation Factor	1.05	1.11	1.13	1.14	1.15	1.17
Total EOI Replacements (Nominal)	**$ 105,761**	**$ 128,730**	**$ 128,250**	**$ 125,627**	**$ 127,691**	**$ 133,859**

Assumptions:

Cost per Unit calculated based on 2022 actuals through October,

Electrical Crew priority 1 and 2 findings, assumes same highest risk structures are inspected annually.

Find rate for risk informed ground inspections is 10.6% for 2023-2028

Find rate for risk informed aerial inspections is 2.4% for 2023-2028

Find rates do not take into account remediations found in field by crews as they are completing other construction work.

OM Forecast: EOI/HFRI Remediations - Distribution

	Forecast 2023	Forecast 2024	Forecast 2025
Distribution OM Breakdown Maintenance			
Number of Priority 1 Notifications[1]	794	814	844
Priority 1 Notification Cost per Unit[2]	$3	$3	$3
Priority 1 Subtotal	$ 2,356	$ 2,416	$ 2,503
Adjustment	$ 78	$ 155	$ 232
Subtotal	$ 2,434	$ 2,571	$ 2,735
AOC Repairs / Replacements			
Number of Priority 2 Notifications[1]	101	104	107
Priority 2 Notification Cost per Unit[2]	$3	$3	$3
Priority 2 Subtotal	$ 300	$ 307	$ 319
Adjustment	$ 16	$ 26	$ 30
Subtotal	$ 315	$ 333	$ 348
Distribution OM Preventative Maintenance			
Number of Priority 2 Notifications[1]	17,687	18,138	18,795
Priority 2 Notification Cost per Unit[2]	$3	$3	$3
Priority 2 Subtotal	$ 52,459	$ 53,797	$ 55,746
Adjustment	$ 3,810	$ 5,624	$ 3,693
Subtotal	$ 56,269	$ 59,420	$ 59,438
Risk Informed Inspections			
Number of Priority 2 Notifications[1]	4,454	4,567	4,733
Priority 2 Notification Cost per Unit[2]	$3	$3	$3
Priority 2 Subtotal	$ 13,210	$ 13,547	$ 14,038
Adjustment	$ 458	$ 891	$ 1,303
Subtotal	$ 13,668	$ 14,438	$ 15,341
Total HFRA Replacements	$ 72,686	$ 76,762	$ 77,862
Escalation Factor	1.10	1.10	1.10
Total EOI Replacements (Nominal)	**$ 79,706**	**$ 84,176**	**$ 85,382**

Assumptions:
Cost per Unit calculated based on 2022 actuals through October,
Electrical Crew priority 1 and 2 findings, assumes same highest risk structures are inspected annually.
Find rate for risk informed ground inspections is 10.6% for 2023-2028
Find rate for risk informed aerial inspections is 2.4% for 2023-2028
Find rates do not take into account remediations found in field by crews as they are completing other construction work.

Workpaper Title:

Transmission Capital

WP SCE-04 Vol. 05 Part 3

Capital Forecast - HFRI & AOC Repairs/ Replacements - Transmission

Transmission Inspection Notifications

Previous Year Notification Roll Over (2023)	Total Notifications (A) [3]	Rollover Rate (B)	Adjusted Notifications (A x B)	Avg Cost/Notification [6]	Total Cost
Ground Risk-Informed notifications due after 2022	117	80.0%	94	$ 37,975	$ 3,554,438
Ground GO95 Risk-Informed notifications due 2022/prior	198	60.0%	119	$ 37,975	$ 4,511,402
Ground Non-GO95 Risk-Informed notifications due 2022/prior	84	30.0%	25	$ 37,975	$ 956,964
Aerial Risk-Informed notifications due after 2022	6	80.0%	5	$ 37,975	$ 182,279
Aerial GO95 Risk-Informed notifications due 2022/prior	57	60.0%	34	$ 37,975	$ 1,298,737
Aerial Non-GO95 Risk-Informed notifications due 2022/prior	58	30.0%	17	$ 37,975	$ 660,761
				Total Roll Over	**$ 11,164,580**

Inspections & Found Notifications (2023 - 2024)	Total Inspections (C) [1]	Find Rate (D) [4]	Execution Rate (E) [5]	Adjusted Notifications (C x D x E)	Avg Cost/Notification [6]	Total Cost
HFRI - Ground	23,501	1.2%	52.0%	147	$ 37,975	$ 5,568,856
HFRI - Aerial	29,401	0.35%	52.0%	54	$ 37,975	$ 2,032,023
AOC - Ground	1,000	1.2%	52.0%	6	$ 37,975	$ 236,963
AOC - Aerial	1,000	0.35%	52.0%	2	$ 37,975	$ 69,114
					Total Found	**$ 7,906,955**
					Total HFRI (2023 - 2024)	**$ 18,765,459**
					Total AOC (2023 - 2024)	**$ 306,077**

Escalation	2023	2024	2025	2026	2027	2028
Transmission (Index)	1.036	1.052	1.059	1.065	1.077	1.094
Transmission (Year Over Year)	3.64%	1.54%	0.59%	0.63%	1.12%	1.55%

	2023	2024	2025	2026	2027	2028
HFRI Repairs/ Replacements - T (Subtotal)	$ 18,765,459	$ 18,765,459	$ 19,053,665	$ 20,505,347	$ 20,634,081	$ 20,865,693
2025 Increase (All HFRI) [2]			$ 1,339,000			
Escalation		$ 288,206	$ 112,682	$ 128,734	$ 231,612	$ 322,993
Incremental Merit Increase	$ 102,198	$ 150,441	$ 308,988	$ 274,164	$ 313,596	$ 358,287
Incremental Division Overheads	$ 997,908	$ 1,066,249	$ 975,183	$ 18,207	$ 860,020	$ 1,714,954
Total HFRI Repairs/ Replacements - T (Nominal $)	**$ 19,865,565**	**$ 20,270,355**	**$ 21,789,518**	**$ 20,926,452**	**$ 22,039,309**	**$ 23,261,928**
AOC Repairs/ Replacements - T (Subtotal)	$ 306,077	$ 306,077	$ 310,777	$ 312,615	$ 314,578	$ 318,109
Escalation		$ 4,701	$ 1,838	$ 1,963	$ 3,531	$ 4,924
Incremental Merit Increase	$ 1,913	$ 2,712	$ 5,755	$ 6,200	$ 6,134	$ 6,134
Incremental Division Overheads	$ 14,959	$ 15,984	$ 13,664	$ 255	$ 12,050	$ 24,029
Total AOC Repairs/ Replacements - T (Nominal $)	**$ 322,949**	**$ 329,474**	**$ 332,035**	**$ 321,033**	**$ 336,293**	**$ 353,196**

Assumptions:

Inspections:

[1] 2023 Inspection numbers from Vegetation & Inspection Strategy as of 10.06.22. 5,900 "Risk 3" structures carved out of scope as compliance.
Number of HFRI Inspection scope (2024 - 2032) assumed to stay the same as 2023

[2] 2025 Additional amounts to HFRI Capital Remediations - $1,339,000. The increase in 2025 accounts for the increase in scope to forecast all High Fire Inspections and subsequent remediations, including repairs or replacements on structures that were only previously counted as part of routine, compliance-based inspection work in HFRA

Roll Over:

[3] Rollover scope as of 8.29.22 from Notif_Pri Report, excluding Capital Notifications scheduled in the GTT (Sept - Dec 2022)

Find Rates:

[4] Ground Capital Find Rate calculated based on 2022 HFRA inspection P2 find rate (YTD - July). Aerial Find Rates for Capital & O&M from Inspections Data Intelligence team - 8.30.22

Execution Rate:

[5] Capital and O&M execution find rates based on aging data from Notif_Pri Report. Total Field Complete Notifications (2022 & Prior) & Time to Complete

Cost Pers:

[6] Capital Remediation cost per calculated using average of Grid pole replacement cost per weighed more towards grids with most inspections (2022)

Capital Forecast - Transmission Splice

Transmission Splice Capital Repairs/ Remediations	Total LineVue Inspections (A)	Forecasted Capital Find Rate (B)	Adjusted Notifications (A x B)	Avg Cost/ Notification	Total Cost
Capital Risk Informed Notifications (2023)	75	3%	2	$ 250,000	$ 500,000
				Total	**$ 500,000**

Escalation	2023	2024	2025	2026	2027	2028
Transmission (Index)	1.036	1.052	1.059	1.065	1.077	1.094
Transmission (Year Over Year)	3.64%	1.54%	0.59%	0.63%	1.12%	1.55%

	2023	2024	2025	2026	2027	2028
Transmission Splice (Subtotal)	$ 500,000	$ 500,000	$ 507,679	$ 510,682	$ 513,888	$ 519,656
Escalation		$ 7,679	$ 3,002	$ 3,206	$ 5,768	$ 8,044
Incremental STIP	$ 2,717	$ 4,003	$ 7,712	$ 6,850	$ 7,829	$ 8,940
Incremental Merit Increase	$ 26,594	$ 28,415	$ 24,297	$ 461	$ 21,428	$ 42,722
Transmission Splice (Nominal $)	**$ 529,311**	**$ 540,097**	**$ 542,690**	**$ 521,198**	**$ 548,913**	**$ 579,362**

Assumptions:
New program in 2022. Find Rate and Cost Per based on limited historical information

Workpaper Title:

Data Platform Governance

WP SCE-04 Vol. 05 Part 3

Business Planning Group: Resiliency
Business Planning Element: Wildfire Management
GRC Activity Wildfire Mitigation and Vegetation Management Technology Solutions
Project: Data Platform/Governance Mitigation Category

Nominal $000 in Thousands

Cost Estimation Sheet

Subactivity	Funding	Recorded 2018	Recorded 2019	Recorded 2020	Recorded 2021	Recorded 2022	2023	2024	2025	2026	2027	2028
Capital:												
SCE Labor	Capital	-	-	-	-	489	3,015	3,572	1,126	1,035	1,032	1,029
Vendor Contract	Capital	-	-	-	-	12,345	6,712	366	365	1,015	1,012	5,050
Software Licenses	Capital	-	-	-	-	-	112	-	-	-	-	-
Other	Capital	-	-	-	-	586	34	1,524	1,015	1,015	1,012	1,010
Total Capital:		**-**	**-**	**-**	**-**	**13,420**	**9,873**	**5,462**	**2,507**	**3,064**	**3,056**	**7,089**

Subactivity		Funding	Recorded 2018	Recorded 2019	Recorded 2020	Recorded 2021	Recorded 2022	2023	2024	2025
O&M:										
SCE Labor	Labor	O&M	-	-	-	-	6	-	-	-
Vendor Contract	Non-Labor	O&M					905	211	208	184
Software Licenses	Non-Labor	O&M	-	-	-	-	-	4,244	4,194	3,712
Other	Non-Labor	O&M	-	-	-	-	301	33	32	29
Total O&M:			**-**	**-**	**-**	**-**	**1,211**	**4,487**	**4,435**	**3,925**

Workpaper Title:

Technology Support Tools

WP SCE-04 Vol. 05 Part 3

Business Planning Group: Resiliency
Business Planning Element: Wildfire Management
GRC Activity Wildfire Mitigation and Vegetation Management Technology Solutions
Project: Technology Support Tools

Nominal $000 in Thousands

Cost Estimation Sheet

Subactivity	Funding	Recorded 2018	Recorded 2019	Recorded 2020	Recorded 2021	Recorded 2022	2023	2024	2025	2026	2027	2028
Capital:												
(1) SCE Labor	Capital	7	2,120	1,867	1,323	866	1,229	826	757	363	361	505
(2) Vendor Contract	Capital	92	7,487	21,898	16,030	8,470	4,462	3,339	1,304	1,004	1,002	1,558
(3) Software License COTS	Capital	-	3,039	1,367	311	28	-	-	-	-	-	-
(4) Other	Capital	0	745	3,566	10,240	(802)	282	283	257	61	61	68
Total Capital:		**100**	**13,391**	**28,700**	**27,903**	**8,561**	**5,973**	**4,448**	**2,318**	**1,428**	**1,424**	**2,130**

Subactivity	Funding	Recorded 2018	Recorded 2019	Recorded 2020	Recorded 2021	Recorded 2022	2023	2024	2025
O&M:									
SCE Labor	O&M	-	1	108	168	156	65	54	46
Vendor Contract	O&M	-	833	2,351	2,794	3,667	549	460	393
Software License COTS	O&M	-	-	22	126	19	1,163	975	833
Other	O&M	-	1,351	395	823	595	2,157	1,809	1,544
Total O&M:		**-**	**2,185**	**2,876**	**3,912**	**4,437**	**3,934**	**3,298**	**2,816**